COMMITTEE HEARING

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

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In the Matter of:                    )
                                     )
Preparation of the 2005 Integrated   ) Docket No.
Energy Policy Report                 ) 04-IEP-01F
                                     )
Re: Strategic Transmission           )
    Planning Issues and Transmission)
    Staff Report                     )
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CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

THURSDAY, JULY 28, 2005

9:40 A.M.

Reported by:
Peter Petty
Contract No. 150-04-002

COMMISSIONERS PRESENT

John Geesman, Presiding Member

James Boyd, Associate Member

ADVISORS PRESENT

Melissa Jones

Michael Smith

STAFF and CONTRACTORS PRESENT

Judy Grau

Joe Eto
Lawrence Berkeley National Laboratory
Consortium for Electric Reliability Technology Solutions

Randall Hunt
Navigant Consulting

Eric Toolson
Pinnacle Consulting

ALSO PRESENT

Randy Howard
Los Angeles Department of Water and Power

James Avery
San Diego Gas and Electric Company

Frank Barbera
Imperial Irrigation District

Patricia Arons
Southern California Edison Company

Chifong Thomas
Pacific Gas and Electric Company

Gary DeShazo
California Independent System Operator

ALSO PRESENT

Kevin Woodruff
The Utility Reform Network

Barry Flynn
Flynn RCI

I N D E X

I N D E X

P R O C E E D I N G S

9:40 a.m.

PRESIDING MEMBER GEESMAN: This is day 49 of the California Energy Commission's 2005 Integrated Energy Policy Report process. I'm John Geesman, the Presiding Member of the Commission's Integrated Energy Policy Report Committee. To my left, Commissioner Jim Boyd, the Association Member of the Committee. To my right, Melissa Jones, my Staff Advisor.

The topic today is the staff's transmission report. We've also got some presentations by a couple of our contractors, utilities, other stakeholders involved in the transmission environment.

This is an area where the staff and our consultants, in my judgment, have made a very impressive contribution over the last couple of years. And I'd strongly encourage us, at some point, to compile a bibliography of the various reports that we have published. Perhaps cluster those on our website, or maybe bring them out in a boxed set. Because I think it's a quite impressive library of the information in the transmission field that I received a great deal of positive feedback from all around the United States as to its value.

We've also done, I think, a very good job in engaging many, if not all, of the stakeholders in the transmission arena in California. It's a difficult problem. I can't say that process has been what any of us perhaps would like it to have been. But we muster on.

Commissioner Boyd.

COMMISSIONER BOYD: Only a couple comments, thank you, Commissioner Geesman. Oh, but I wish it were true that this was day 49 in the IEPR process. You said welcome to day 49; I know what you meant was welcome to hearing number 49. I think the days you've got to put a zero at the end of the 49.

The only other comment I would make, I certainly take a lot of my bead in transmission from Commissioner Geesman, who is to be commended for his dedication to this subject. It's an issue we identified in the very first Integrated Energy Policy Report in 2003 as something desperate for attention in the state. And he has taken that challenge and we continue to push the subject. And it's a subject certainly deserving of being pushed and dealt with.

And so I welcome this hearing and all the input and the commentary I hope we get from a lot of you out there on this subject, because it certainly will be prominent in the 2005 report that we recommend to our Commission, I'm sure. So, thank you.

PRESIDING MEMBER GEESMAN: Judy.

MS. GRAU: All right. Before we get started I have a couple of housekeeping items. Those of you who have been here before know that our restrooms are located over there. That's true for the mens restroom, but the ladies restroom over there is out of order, so the restroom we're now using is behind the guard shack, if you head toward the back of the building, toward the freight elevator. Before you get there, on the right you'll see womens bathroom for your use.

The coffee shop is located on our second floor up the stairs behind the guard. We ask that you please use the main entrance by the guard station to enter and exit, as the side door over there is alarmed and it's for staff use only, who have badges.

Okay, with that I'd like to just speak

briefly about the structure of today's hearing. It's divided into two parts. Part one covers strategic transmission planning issues. For those of you who attended the Committee's May 19th workshop, one of the 49, we had a workshop on transmission corridors and strategic plan update number one. And you will recognize many of this morning's part one topics as a continuation of that workshop.

At that May 19th workshop Mr. Joe Eto of CERTS presented his review of the Cal-ISO's economic evaluation methodology for the Palo Verde-Devers 2 transmission project. Today Joe will be presenting his review of Southern California Edison's economic evaluation methodology for the same project.

Also at the May 19th workshop Navigant Consulting provided background material on transmission congestion in southern California; as well as the transfer capability between LADWP and SCE service territories.

Navigant also briefly noted its ongoing work evaluating the reliability benefits of economic transmission projects. And today Mr. Randall Hunt of Navigant will update us on those works in progress.

At the May 19th workshop Mr. Eric Toolson of Pinnacle Consulting shared his work in progress in which he surveyed stakeholders about potential criteria that should be used to evaluate transmission projects and their alternatives in order to provide decisionmakers with a means to compare alternative resource portfolios.

Eric is here today to share his distillation of that input into a short list of proposed criteria. He also has a presentation on the assessment of low-probability/high-impact events. So that's the content of part one.

And then part two covers the transmission staff report that was published on our website on July 20th. And if you haven't already brought your own downloaded copy, please make sure to pick up one at the green-covered reports from the back table.

And as I will mention again when we get to part two, the Energy Commission will be developing a strategic transmission plan. And staff views this report as one source of information that the Commission can use to develop this first strategic plan.

We will also be hearing from several utilities on what they think should be included in the plan. We welcome any others not listed on the agenda to share their thoughts on either the staff transmission report, or the strategic plan, or both.

So we're going to now get started on part one with Joe Eto of CERTS.

MR. ETO: Thank you, Judy. Good morning, Commissioners, Staff, hearing participants. It's a pleasure to be here. My name is Joe Eto; I am a staff scientist at the Lawrence Berkeley National Laboratory where I manage the program office for the Consortium for Electric Reliability Technology Solutions.

I'm pleased today to have a chance to prepare and offer remarks into the IEPR process on a review that you've asked us to conduct, looking at Southern California Edison's economic evaluation methodology for the Devers-Palo Verde Line number 2.

Before I begin I'd like to also acknowledge the contributions of Dr. Fred Mobeshari from the Electric Power Group, who was the lead analyst for the work that I'll be presenting.

Just like to start with a little bit of background. The Commissioner mentioned some of the work that had been done over the years in supporting this process, and I wanted to just touch bases on sort of how we got to the point of the review that I'll be presenting to you today.

Two years ago we presented an assessment of historical transmission investments in California, and identified a number of benefits unplanned at the time, or unaccounted for at the time of construction, that were realized as a result of the building of those lines, which substantially enhanced the value of those lines to California.

That really led us to then think about looking forward what role transmission might play in California's future.

We then conducted a scenario analysis that looked at electricity and transmission interconnections in a variety of different alternative scenarios. And reached the conclusion that under any reasonable scenario future resource, endowment or acquisition for the state, that out-of-state transmission would be an important part of that resource portfolio.

And that therefore it would be very important from a policy perspective to begin laying the groundwork for those types of investments.

Toward that end, last spring we made a review of transmission planning methodologies and made a number of recommendations regarding ways or types of strategic benefits and analyses approaches that would be appropriate for better capturing all the values that transmission brings into this type of a planning process.

We have followed that this year, starting last May at the workshop that Judy just mentioned, by reviewing the economic evaluation methodology that the California ISO had undertaken, looking at the Devers-Palo Verde line 2.

This is really the second portion of that discussion, which I'll now talk about a review of the economic evaluation methodology that Edison has used in supporting the Devers-Palo Verde 2 application.

To review, where we came into this process was through the identification of a number of important strategic benefits that we felt needed to be addressed in some capacity in order to conduct a comprehensive evaluation of specific transmission projects.

One of the key benefits of transmission that we think needs to be included is the opportunity for transmission essentially to enlarge the market for generation. And contribute to price stability by again decreasing the market power of existing generators by essentially enlarging the scope of the market that might be available to a given set of loads.

I think there's also the potential for increased reserve sharing and firm capacity purchases when you have these interconnections. And one of the most important things I think really has not been well addressed is, you know, a lot of the analyses focus on expected values and business as usual. But we all know in California that business often isn't as usual, and that one of the critical strategic benefits that we think transmission plays is an insurance policy against contingencies during abnormal system conditions.

And in our historic review we found numerous instances of just these types of contingencies and the tremendous benefits that transmission brought to our state that, again, weren't captured or anticipated at the time of the planning or the construction of these lines.

There's also potential for environmental benefits. And in particular, also the issue of looking at additional infrastructures that are impacted by transmission in the form of gas pipelines.

So let me talk about what we've done in trying to look at the Edison application through the lens of these strategic benefits, as well as the methodologies that were employed.

We were asked to review a large number of documents that Edison prepared, and we focused really primarily on these two documents, chapter 2 of the performance environmental assessment, and then the appendix looking at the cost effectiveness analysis, both the initial report and then its update last March.

What we were trying to do really here was then just sort of examine not so much as a critique of the assumptions or the outcomes, but what were the methods being used, what were the types of benefits that were being captured, how were they being captured. And specifically to sort of lay that against the scope of strategic benefits that we identified as being important for consideration in these types of planning exercises.

One of the critical recommendations that we made in our strategic assessment was the importance of looking at it using a social rate of discount in some of the more societal perspective analyses.

Now, we're going to try to apply that to one perspective looking at some of the information from the Edison filing.

So, as a starting point for that review, let me review the objectives that Edison articulated for building Devers-Palo Verde 2. I think, again, primary among them was being able to access the low-cost energy in the southwest.

Edison's assuming about 6500 megawatts of power being additionally available to California over Devers-Palo Verde 2; and access to that would be a significant cost reduction to the cost of power in the state.

They also are interested in understanding how it would affect competition, as again looking at this issue of expanding the market for generation that might compete for load in California.

They're also looking or considering the ability of the infrastructure to support additional construction beyond the assumptions that are in the generation portfolios currently as a way of bringing more energy into California. And I'll speak specifically to that issue in our review of the methods, because, again, what you assume about what is in -- is very critical in terms of trying to assess the value of what you can and can't capture at this point.

And then finally, Edison mentions the issues of the reliability supply and the insurance value against extreme events and the flexibility and operating of the transmission grid more flexibly. But, again, one of the things we'll comment on is having mentioned those there's little quantification of those. And from our perspective, you're in the framework of benefit/ cost analysis if you mention something but you're not able to put a number to it, you're effectively putting the number zero to it. And so we think that's something that -- but we think that there are ways to begin to try to address that. We encourage the stakeholders to begin trying to do that.

So looking at the economic benefits that were quantified by us, and again it's primarily the energy cost savings. Again, building this line, accessing lower cost out-of-state generation essentially is going to lower the total production cost within California.

Edison's analysis suggests that California's prices would fall by about 2 percent through the construction of the line. And this is the principal economic benefit that's focused on in the filing.

There is a small amount of impact on transmission revenues. It's really quite minor in size compared to the economic benefit in terms of lower overall total production costs.

Some of the things, again, that were identified but were not quantified by Edison was this issue of new generation development. In both of these production simulation cases the portfolio generation's assumed to be fixed with and without the construction of the line.

A key question looking forward is the

extent to which the very existence of that line might inspire additional construction of generation beyond that assumed in these with and without cases.

There is this very significant issue of market power which the types of techniques that are being used are only beginning to scratch the surface in capturing. I think the CAISO methodology attempts to do this. To my knowledge, it's not explicitly factored into the way in which the Edison evaluation took place.

And finally, of course, this emergency value is something that is mentioned, but, you know, we are still looking at the methods for trying to capture that at this point. And I think it's a very important topic going forward for something to develop.

Now before I go into the Edison's evaluation and our analysis of it, I want to make some comments sort of in contrasting. This is not the first analysis of Devers-Palo Verde 2. The CAISO also has attempted to look at the benefits and costs of that line.

And I wanted to just sort of say, you know, these are different methods. You know, the basic idea is production simulation, but there are different ways it's being done. I wanted to sort of like compare the two approaches. And I also want to clarify one of the statements I made.

You know, the Edison evaluation looks at a number of operational benefits. There are some other operational benefits that I think the CAISO captures, and I want to right now correct a misstatement or a typo in this presentation.

In here it says it assumes that Edison's evaluation assumes there will be no capacity benefit. That's not -- what Edison does is they conclude that there will be no capacity benefit, although they do consider the opportunity for capacity benefit. This is in contrast to the CAISO evaluation which does both consider and conclude some capacity benefit from the availability of surplus capacity in Arizona.

Edison also makes an estimate of transmission losses but believes it's really inconclusive. And again, this is kind of an issue of methodologies in terms of the sophistication of the power flow types of simulations that are used in doing these analyses.

The CAISO does attempt to do it through

an external means, recognizing the limitation of the existing DC power flow not to be able to capture those things.

Both try to capture emission reductions. The ISO evaluation goes on to look at the CO2 benefits, again through an external calculation.

Now, I'm really not trying to do this to sort of, you know, do a beauty contest, but really what I want to do is to try and look at the scope of benefits that are or aren't captured. And in the context, you know, it's instructive to look at the CAISO evaluation. And when you look at these additional things that are being considered here, you see that about 30 percent of the total benefits are from things that are not directly captured, or were found to be zero in the Edison evaluation.

So, again, what I'm trying to say is these methodologies of what is captured and how it is captured is very important. And I want to emphasize that in terms of things to begin thinking about as we look forward toward more comprehensive evaluations of the worth of these activities.

So, in terms of the life cycle benefits, Edison does a benefit/cost ratio using a nominal 10.5 percent discount rate. And, again, the principal benefits here are the energy benefits; it's about over a billion dollars. There's a small amount of this third-party transmission revenue benefit. And then compare that to the revenue requirement which they estimate at about -- which we estimate, based on their information, based on about $650 million, and you get a benefit/cost ratio of about 1.7.

And so, you know, this is their fundamental finding from the Edison evaluation focusing really on a CAISO ratepayer perspective, which is appropriate for the scope of the type of evaluation and the filing that Edison is making in the venue that it's making, which is to the PC, which, of course, is concerned about ratepayer costs.

Now, one of the things that we've done, which was outside the scope of Edison's evaluation, was to take some of the production cost information, looking at the WECC impacts as a whole, and begin to try again put it into this type of a framework.

So what we have done is taken the

initial simulation years of the production cost benefits, looking at the WECC region as a whole, extrapolated those out to the lifetime, the expected lifetime of the line; done a present value calculation at the social discount rate that we recommend, and calculate benefits on the order of $135 million. And we also make a projection based on the transmission -- but, again this is a very small part of the calculation.

So when we do that, looking here on the left -- on the right side of this screen you have the CAISO ratepayer analysis that Edison has just presented in their filing of benefit/cost ratio of 1.7. If you now take the work that we have done looking just at the production cost benefit from the WECC perspective, you'll get net energy benefits of about 435 million; total benefits of about 500 million, which is less than the capital cost that we estimate for the cost of the project.

And so from a WECC perspective, based on this set of benefits, we would conclude that the benefit/cost ratio is less than 1.

I think this is instructive in terms of what the dynamics, and I just want to kind of maybe explain a little bit of the dynamics, so you understand the difference in the net energy benefits, since they're basically the same types of benefits, but looking at it from different perspectives.

Essentially the dynamic here is that low-cost generation from the southwest is displacing very high cost generation here in California. Well, in terms of meeting the needs of the rest of the west, they're going to have to rely on other sources of generation to meet those needs, other than the low-cost generation that's now coming into California. And that, in effect, raises their production costs.

So, as a region as a whole benefits in production costs, California benefits somewhat disproportionately in terms of what's being displaced as being very high cost in California.

So let me just summarize then what we are finding. You know, based on looking at a California ratepayer -- CAISO ratepayer perspective, the benefit/cost ratio is greater than 1. Looking at this WECC regional perspective, using the production cost numbers developed by Edison, but valuing them at a social discount rate, we find that the benefit/cost ratio is less than 1.

But, again, going back to our assessment of the methodology, part of the reason that the regional benefit is low in this case is because many of the values, the strategic values in terms of the insurance value, the reduction in the potential for exploitation of market power, the potential for development of new generation outside of California, other operational benefits, environmental benefits, and, of course, impacts on the gas infrastructure, are simply not captured in this type of a calculation.

And so going forward, you know, we would recommend that much more comprehensive evaluations of the total cost and the total benefits of these projects be undertaken. Among the things to be concerned about is this interaction between the capacity benefit and the transmission and generation expansion question.

Again, one of the key things that comes out from looking at the simulation studies is the generation portfolio is basically held fixed between the with and without transmission scenario, when in fact we would submit that the existence of a large transmission line to bring low-cost power into California would likely inspire additional construction of generation in the Palo Verde area that might be available both to California and to the rest of the west.

Something that's very very important that we've said many many times, of course, is this question of insurance value. This really is something you cannot capture through an expected value calculation. Requires much more of the probablistic and scenario type of evaluation to again look at extreme events and look at the worth of transmission in trying to sort of help you through those difficult but unanticipated situations.

We think there are a lot of environmental benefits that need to be captured. Impact on the infrastructures, such as gas pipelines should be included. And, of course, a lot of the operational benefits in terms of the operational flexibility of redispatch certainly need to be considered in these types of assessments.

So, again, in conclusion, I think within the scope of what Edison is charged to do in the context of the filing with the PC, I think the ratepayer impact from production cost is a straightforward and appropriate calculation. We would suggest additional types of considerations be brought into the overall planning process for the purposes of trying to assess from a societal perspective the value of these types of projects.

With that I'll conclude my remarks.

PRESIDING MEMBER GEESMAN: Joe, let me ask you a question on the environmental benefits you refer to in item 3. You're speaking of air quality benefits, are you not?

MR. ETO: In this case the ones that have principally been captured in the studies to date have been the air quality benefits. You know, Edison looks at a variety of the control pollutants; CAISO adds to that this issue of CO2.

PRESIDING MEMBER GEESMAN: What other environmental benefits would you then envision being appropriate to attempt to capture?

MR. ETO: Well, I think there are going to be corollary impacts on gas infrastructures that it's going to have implications for. And I think also an important thing that's not directly captured in these environmental calculations, at least from a total production cost perspective, are the distributional aspects of where the pollutants, in effect, are being emitted. As well as other --

At the same time, you know, for completeness, I think it's also important that we consider the environmental impacts from constructing these lines. And, again, the issue is that there is lots of benefits in cost; there are many affected parties. And we are better served by a more comprehensive assessment of these than by snapshots of portions of them.

PRESIDING MEMBER GEESMAN: Did the Edison analysis focus strictly on NOx reduction?

MR. ETO: No, no, I'm sorry, this is an incomplete statement here, in that Edison did consider all the controlled pollutants.

PRESIDING MEMBER GEESMAN: Okay.

COMMISSIONER BOYD: Joe, just a comment. I want to commend you on your presentation and your analysis. All my working career I've had trouble with the cost/benefit analysis because, a) it's been usually narrowly defined because of the incredible difficulty of assigning quantifiable numbers to shove into the equations on so many of these other attributes that should be taken into more like called a full absorption, from cost accounting, full absorption analysis.

But I think you're right on point. That's something we need to grapple with. It becomes more and more difficult, but so is life, and so is everything else. So, I appreciate your presentation. It was quite good.

MR. ETO: Thank you. I'd like to actually comment in two ways on that. You know, I think it's very important to recognize that the benefit/cost framework is a decisionmaking tool. It is not a substitute for a decision.

And particularly in regard to your earlier comment, you know, I'm harkened to something that I heard many years ago, which is you shouldn't confuse the things that you can count for the things that really count.

And that is especially true in the discipline that cost/benefit analysis directs you toward, which is to focus on the things that you can count.

COMMISSIONER BOYD: Good point. The trouble is there's so few of us who remember or ascribe to that statement. And I agree with you 100 percent, it's a tool. The trouble is historically, in my opinion, too many people have made it the decisionmaker, maybe to hide behind or as a shield. But, good point.

PRESIDING MEMBER GEESMAN: I guess on that note let me ask you a question that we've touched upon repeatedly throughout the last couple of years in these workshops. How does the Edison analysis address the question of what is the appropriate period of analysis for the decisionmaker?

You're dealing with infrastructure with what we've previously estimated to be a 30- to 50-year useful life. You apply a discount rate of something; we've suggested a social discount rate; you've used 5 percent. How does the Edison analysis address that?

MR. ETO: Well, the Edison analysis does consider the lifetime of the transmission investment. And then looking again from the ratepayer perspective and the revenue requirement discipline they do use the nominal discount rate that would be associated with an Edison investment.

And from a ratepayer revenue requirement it looks like that would be appropriate. The methods that they use to get to the lifecycle benefits are five years of simulation, which is in contrast to the ISO's approach, which was two years of simulation.

But, again, you're basically looking at the first couple of years, and then you're making extrapolations from there.

PRESIDING MEMBER GEESMAN: I guess the concern I have, it continues to represent a problem in my mind. A discount rate that you apply really to many of these criteria, if it's a 10.5 percent discount rate it means benefits after, I don't know, year six, year seven, count for nothing.

If it's a 5 percent discount rate, you've extended that horizon a bit, but you haven't extended it to the full service life of the equipment.

I think about the Golden Gate Bridge. It continues to provide benefit to northern California and the people that live within northern California today. But we're clearly beyond any time horizon that a discount rate would have captured those benefits.

How does government deal with that

conundrum?

MR. ETO: Well, I have a couple of reactions to that thought. You know, I think, you know, certainly the discounted cash flow, again, tool that is used in decisionmaking really is looking at the opportunity costs for those capitals. And that's, you know, where the discount rate comes in. What would you otherwise do. And that's the basis for the comparison.

At the same time it's very clear that, you know, there are many long-lived assets that have benefits that often exceed their lifetimes.

I think I would probably frame it more from the standpoint of some of the things that the discount rate and these methods can't, by themselves, directly capture in the way they're being applied. Which is, again, going to this insurance value question, you know.

Part of the benefit here is a protection, you know, a policy against certain bad things, and your ability to deal with them more flexibly when they occur. And to me, you know, that's a clear area to push on.

Beyond that, you know, within the discipline of the cash flow method, you know, moving toward the social discount rate is probably as much as you can ask of that type of decisionmaking tool and framework.

PRESIDING MEMBER GEESMAN: Thank you very much, Joe.

MR. ETO: Thank you.

MS. GRAU: Okay, our next speaker is Randall Hunt of Navigant Consulting.

MR. HUNT: My presentation is mostly congestion issues. And then item B is a quantification of operational reliability benefits of economic projects. That one we're probably going to defer on today because we've already got a draft report completed and we're kind of waiting for comments and feedback on it. So mostly we're going to focus on A and C today.

PRESIDING MEMBER GEESMAN: What's your timeframe for B?

MR. HUNT: You know, I honestly don't know. I'm sorry. As for the turnaround and completion, you mean?

PRESIDING MEMBER GEESMAN: Yeah, when can we have something in our docket that we can officially rely upon?

MR. HUNT: Yeah, can I get back to you

on that one?

PRESIDING MEMBER GEESMAN: Sure.

MR. HUNT: Okay, thanks. Okay, again, here's a map of the way I see southern California and the congestion issues. Of course, we have Palo Verde West, a branch group which comprises the Palo Verde-Devers and basically Palo Verde area to north Gila. Can I point to these things somehow? Yeah, I guess so.

And then we have a -- okay, thanks. All right, and then we have a Imperial Valley-North Gila 500 kV line, which is also a congestion issue. We have a tie at Sylmar between Edison and LADWP that has been a congestion issue.

Next I'd like to show you just a quick table of the Palo Verde area new generation projects. Probably everyone has seen this already. But there's various numbers on the capacity that was added there, but it comes to an average of 3500 to 4000 megawatts that's been added there over the last two to three years. Leading to a great many of the congestion issues.

And back to this picture, the generation that's shown down here is what's referred to, I think, by the ISO as the border gens. Which is generation that's located down in Mexico and feeds into the Imperial Valley, also contributes a great deal to congestion.

This is a diagram that shows kind of one line of the congestion into southern California. The PV branch group, which is those two 500 kV lines. And then the lines coming in from Mexico. And at the time, 2003 and 2004 that we were directed to look at this, this particular transformer right here was a problem that has since been fixed.

As I said, the PV branch group is those two 500 kV lines west of Palo Verde. The PV area generators bid into the ISO market; and the bids are competitive as the plants are relatively new and efficient. And they get cheaper gas rates over there, I believe.

The last bullet there I found out just yesterday is a little bit wrong. That the ISO has apparently not had to bypass the series caps. It was a path rating issue. However, there were some hours where the actual flow in the branch group did exceed the rating of the branch group. Not a real big deal; that happens in congestion management now and then,.

And during 2003/2004, during the high congestion cost times, the constraint was that Miguel 500 to 230 transformer that I mentioned. And then now it's evolved more to the system from Miguel on into loads in the San Diego area.

And what it resulted in was dec'ing, or decrementing on the border gens, those ones down in Mexico, to relieve congestion on that transformer at Miguel.

Well, in October of 2004 a second transformer was added at Miguel, greatly relieving the issue. And adding about 400 megawatts of capacity on the path.

Although the congestion problem had been greatly reduced, congestion now moved to south of Miguel and resided there for about -- well, since about a month ago when San Diego finally placed the Miguel-Mission 230 kV number 2 line into service. Granted, it was ahead of schedule, but it's done a pretty good job at relieving congestion. And now they're to, I think, about over 1800 megawatts, for a gain of about 700 megawatts on the path.

PRESIDING MEMBER GEESMAN: Are they operating that at a higher voltage rating?

MR. HUNT: I believe it's operated at 230, but I'm not sure on that. If there's a San Diego rep here, maybe you could confirm that.

COMMISSIONER BOYD: I see yes nods.

PRESIDING MEMBER GEESMAN: Okay.

MR. HUNT: Okay, all right. The congestion management on Miguel was physically successful in that there were only a few hours where the flows drifted above the transfer limit.

And between July 2003 and September 2004 approximately $32 million was spent on redispatch alone. And what I mean is redispatch is the inc'ing and dec'ing. In other words, bringing the Mexican generation down, border gens down, and then probably local generation in the San Diego area up.

And on top of that redispatch costs, the ISO has incurred what they call MLCC, which is minimum load cost compensation, and RMR operating costs. And when you add those in, the actual expenditures for the congestion are much higher than the 32 million.

There's several projects out there in the works, the first of which is east of the river, 9000-plus, which is a study, I believe, being conducted by the Salt River project, to do the serious capacitor upgrades, the small fixes and whatnot that would gain about 1000 megawatts of total capacity in the EOR.

Now the PV west branch group wouldn't, of course, get all of that. There would be some sort of a pro rata share for that path.

And then the next one is as was mentioned before, the Harquahala-Devers, or also known as Palo Verde-Devers, and the phase 2 study report for WECC was just completed. The project should be in service by '09 or '10.

And then the last one is San Diego is studying options for a new line from somewhere in the Imperial Valley area probably to somewhere in the central to northern portions of their system.

Congestion management costs. Again, the redispatch costs total to 32 million. And this is probably in the same range as the cost for the Miguel and Imperial Valley 230 kV transformers.

PRESIDING MEMBER GEESMAN: Do you have numbers for the MLCC or RMR costs?

MR. HUNT: Total, yes. But not allocated by congestion problem. I wish I did, but I don't.

PRESIDING MEMBER GEESMAN: Is there any way of deriving that?

MR. HUNT: Not from the data we have. We'd have to get it from the ISO somehow.

PRESIDING MEMBER GEESMAN: Okay.

MR. HUNT: And I'm not sure they even track it by the particular congestion issue. I'm not sure of that.

PRESIDING MEMBER GEESMAN: Okay.

MR. HUNT: Okay, and the next one is kind of a speculation that if another 1000 megawatts were added to the border gens next year, the transmission cure to fix that congestion couldn't be built until about 2010 or beyond. Because the first one, the congestion for the existing border generation, there were little tiny tweaks and upgrades that could be built. The next one's going to take a big line.

And so what I'm getting at here is you would have to live with congestion for a long time until the line actually got built.

PRESIDING MEMBER GEESMAN: Well, would it make more sense to prebuild?

MR. HUNT: I wouldn't say that it would be, no. I couldn't venture that guess.

PRESIDING MEMBER GEESMAN: Okay.

MR. HUNT: It's a fairly expensive transmission like Palo Verde-Devers, also.

Okay, then the last bullet is the ISO's amendment 50 to establish the reference dec bids and mitigate the dec gaming, was already in effect for the time period above. So the 2003 to 2004, July of 2003, the reference dec bids were in place.

The bigger picture. This is kind of getting to that 1000 megawatt speculation thing. The problem here is that the generation can site and construct much faster than the lines can be built. So what you do is you live with congestion management for the duration in between. And it gets expensive.

Congestion management cost signals are not forward looking. And I would think the ISO needs a tool that would somehow predict congestion management costs and get the transmission upgrades in a more timely manner.

PRESIDING MEMBER GEESMAN: And in saying that, you would include MLCC and RMR costs as a congestion management cost signal?

MR. HUNT: Yes. Now there's a bit of a

dispute potential there because of the fact that the MLCC, while used for congestion purposes, it's called on to run in a particular day to solve a congestion problem; it also serves the net short load for what the ISO might have to make up in the market --

PRESIDING MEMBER GEESMAN: So 100 percent of it is not attributable to a congestion management cost?

MR. HUNT: I believe that's correct. The issue is that when the machine is called for the run the next day the reason it's called is how it goes into, I believe, ISO's tagging; what they call the select system. To where it's tagged, it says we needed this unit for congestion management.

PRESIDING MEMBER GEESMAN: And yet in the Miguel example that you use, you don't think the ISO has necessarily retained data that would attribute certain MLCC costs to congestion management?

MR. HUNT: Well, I don't think they've identified it by path. And I don't think they've split the cost of here's how much of this cost benefitted congestion and here's how much benefitted the net short for the next day's load.

PRESIDING MEMBER GEESMAN: And that would presumably vary path by path by path?

MR. HUNT: Oh, yes, I think it would.

PRESIDING MEMBER GEESMAN: So you couldn't apply a systemwide or regionwide assumption in terms of working out such a split?

MR. HUNT: No. I would think it would have to be the real-time operator at the time that identified this MLCC unit as being called to run the next day for this path. And it provides so much benefit for congestion and so much benefit for serving the load.

PRESIDING MEMBER GEESMAN: What about RMR costs? Is there a way to objectively attribute a portion of RMR costs to congestion management?

MR. HUNT: I would think there would be. But, again, the exact functional details on the floor at the ISO, I don't know how they would keep track of that basically, on an --

PRESIDING MEMBER GEESMAN: Okay.

MR. HUNT: -- accounting basis. Okay, the next one, as I said, we're going to skip over the operational reliability benefits because we do have a draft out there already for review.

And the last one is the assessment of LADWP to SCE interconnection issues. And here, again, I've got another map. I like maps.

The major interconnections that are kind of closer to California are, of course, the 500 kV Eldorado-Lugo, which is out in Nevada. And then we've got a Victorville-Lugo 500 kV tie, also known as Path 61. And then we've got a tie at Sylmar 230, which is also known as Path 41. And I've tried to identify LA's approximate service area in there.

And this gets down to a little more detail into the area of interconnections into the L.A. Basin. And this is that Sylmar 230 kV tie and the lines that go out to Eagle Rock and Gould, and then back to Pardee on the Edison system.

And then there's an emergency tie between Velasco and Laguna Bell that is not operated in service. It is typically open. I don't believe, in fact, it's been closed for a long time.

Oh, of course, I forgot to mention all this stuff. The red stuff is the 500 kV and blue is 230. And these are L.A.'s century lines that come in from Victorville. And they are 287 kV.

And here is what's called a nomogram between Victorville-Lugo and the Sylmar interconnection. And what I'm trying to point out here is what says existing is actually now old and outdated. It's 800 megawatts with a bit a corner cut off there.

And now today, with the new transformer that was added on Path 41 at Sylmar, they've got it up to 1600 megawatt rating with no corner point. So the paths are basically independent now, a pretty healthy upgrade.

And then this is a configuration of the Sylmar buss; and this is the transformer that was added. And this transformer was added, I believe, in December of 2004. So this transformer came in after all of the nasty congestion costs were incurred here.

This is a graph of total intrazonal congestion costs which, I think, can be interpreted as total congestion costs, also. And the yellow -- doesn't show up as very yellow there, but the top bar shows the redispatch, which is the inc'ing and dec'ing issue. And then the red shows the RMR costs and the blue shows the minimum load compensation costs.

And you can see the MLCC is a fairly substantial component of the total cost picture. But, again, we've got that cost sharing that it also serves load issues, along with congestion.

PRESIDING MEMBER GEESMAN: And this is Edison?

MR. HUNT: No, this is total.

PRESIDING MEMBER GEESMAN: Total meaning ISO controlled?

MR. HUNT: ISO total, right, --

PRESIDING MEMBER GEESMAN: Okay.

MR. HUNT: -- of which there are quite a few different ones, but we're going to point out in a little bit that some of these really stick out as major cost issues.

And, again, as I said, the MLCC units are called for congestion relief purposes. Then they're tagged toward this accounting of the -- on the graph here. Now, there are other MLCC costs that are not on here. This is not a total MLCC cost. This is just when it was tagged to congestion.

PRESIDING MEMBER GEESMAN: But I thought when we talked about San Diego you said they didn't tag MLCC costs to congestion management.

MR. HUNT: Oh, I'm sorry, I must have misunderstood you. The ISO does the MLCC tagging. And what I don't know is that they tag it for a specific congestion path.

PRESIDING MEMBER GEESMAN: Oh, okay. Okay.

MR. HUNT: And, again, the RMR costs are attributed to congestion when they're called for generation levels above RMR requirements. And then the total congestion costs includes the three components.

Here we get down into some information about the specific paths and the congestion that was racked up on those. And right here we have the component, which has been identified as a three-week Sylmar bank outage. And I believe that outage was called -- that's the original two 600 mva transformers from that one-line diagram. And they had to take one of them out of service. And the L.A. folks think it's for -- the opinion that I got was that it was for a maintenance, transformer maintenance, regular maintenance cycle. But it was rather expensive.

And most of these costs that are shown

here were for decrementing generation to relieve the congested path.

We have another biggie for Sylmar out in this area here that was due to the reconfiguration of the station and outages during the DC upgrades; when they split the DC from its 2000 megawatt and 1100 megawatt expansion project, to where it's now split 1550 per pole, and half of it goes into Edison and half of it goes into L.A.

Can also see in this graph the yellow parts on the bottom, which are the Miguel redispatch, also one of the major striking cost components to the redispatch congestion.

And, by the way, this document is taken from -- this is public information -- this was taken from the ISO DMA reports.

PRESIDING MEMBER GEESMAN: The Miguel redispatch costs don't seem to have much correlation with peak load or seasonal peaks. Is there a reason for that?

MR. HUNT: Yes, probably, but I don't know what that is right now. Yeah, I'd just be speculating, sorry.

Congestion for that three-week Sylmar bank outage was approximately $9.8 million. The reason for the bank outage was not firmly identified, while the L.A. folks think it was probably maintenance, but he wasn't sure.

The congestion identified in December, the later part of that graph, was caused by the DC upgrades. That totaled to $32 million.

The DC terminal construction and testing continued until December, so there was actually information beyond this curve here where costs were still being racked up. And, again, those congestion costs were primarily paid for dec'ing machines, decrementing machines, but we don't yet have the information on exactly where that decrementing happened. I would speculate that it was in the LADWP area.

Recent system upgrades include the fact that LADWP installed that third transformer and increased the path rating to 1600. In December of 2004 the PDCI terminal work was completed, and now the flows on the poles balances with Edison's buss and one into L.A's buss. This reduces the congestion across the transformers at Sylmar.

Possible system upgrades include the fact that LADWP is repowering Haynes Valley and Scattergood with more efficient combined cycle generation. And it appears that LADWP sometimes bids these resources into SCE and the ISO markets resulting in congestion at Sylmar. If Sylmar congestion continues additional capacity may be beneficial.

Other interconnection options would include rebuilding that Laguna Bell-Velasco 220 to 230 kV emergency tie. It would have to be rebuilt pretty stout. It's a rather small low conductor size right now.

A new Adelanto-Lugo 500 kV line, along with flow control devices at Sylmar to curtail the flows across that path. And then in 1994 L.A. identified an option of upgrading the Victorville century 287 kV lines to 500 kV with a loop in of the Lugo-Serrano 500 kV line. I've not seen that configuration mentioned by anybody, so perhaps it died.

PRESIDING MEMBER GEESMAN: With regard to the Laguna Bell-Velasco tie, is there a need to maintain some similar emergency tie that's not utilized, but is available?

MR. HUNT: You know, I don't know whether there's actually a need for that emergency tie today. At one time there was a 220 to 230 transformer, I believe at Velasco.

There's one difficulty with that tie in that the 230 kV system is, in many ways, in LADWP's area and Edison's area, near its fault current interrupting limits. And anytime you make a tie like this that really upsets that balance. And you would end up replacing a lot of breakers in each system. So the cost of this tie is not just the interconnection, itself, but the other upgrades you would have to make in the system.

PRESIDING MEMBER GEESMAN: So is it really envisioned then as an emergency tie, or simply a facility no longer utilized and has yet to be permanently retired?

MR. HUNT: I think that latter conclusion is probably about the best.

PRESIDING MEMBER GEESMAN: Okay.

MR. HUNT: The bigger picture here. The congestion management is supposed to send pricing signals as to when the transmission upgrades are needed. Well, these are pretty expensive signals, these costs that rack up here, to the point that the congestion costs for ten months of operation would have paid for several new transformers at Sylmar.

But, the trouble is, this congestion management is not forward looking typically. And I would think that's what somebody would want here, is some kind of a tool that would say we need to look forward and see where congestion could be, or perhaps will be, and try to avoid spending money that is now gone and not available for new facilities.

PRESIDING MEMBER GEESMAN: One of the things you said regarding the way the RMR costs are tagged as congestion related, I believe the way you described the existing ISO methodology is to only count costs above the existing RMR contract level?

MR. HUNT: I believe that's correct, yes.

PRESIDING MEMBER GEESMAN: What the plant is run above the existing RMR contracted level. Don't a lot of these RMR contracts in fact exist because of inadequate transmission interconnection?

MR. HUNT: Yes, but I believe that was based on a local pocket issue, a load pocket import, if you will, issue. This is a congestion issue, --

PRESIDING MEMBER GEESMAN: Okay.

MR. HUNT: -- which is --

PRESIDING MEMBER GEESMAN: Okay.

MR. HUNT: -- a different story.

PRESIDING MEMBER GEESMAN: Thanks very much.

MS. GRAU: And our next speaker is Eric Toolson. He has two presentations which he will do back-to-back. There are separate handouts, though, for those of you who are picking up the handouts.

MR. TOOLSON: As Judy mentioned I have two presentations I'd like to make. The first one, those of you who participated in the May 19th workshop, have already listened to part of that, and I'm going to review that quickly and then go into the conclusions here.

Okay, the first one we're talking about the valuation criteria. And from that we think that there's three purposes for that, at least three. One is to provide a standardized methodology when comparing resource transmission portfolio alternatives.

So that if you're going to propose a transmission line as a utility, as a transmission owner, you know how it's going to be evaluated. There's some standardization to it. It's clear how it's going to be evaluated, it's clear how it's going to be evaluated with the other factors.

You understand if it's just an economic evaluation, or if there's subjective factors that go into it. What are the factors that are considered; how are they weighted; so on and so forth. So I'm going to talk a little bit about that, some ideas that aren't necessarily mine, but ideas that have been shared with me through a stakeholder process that I'll define for you.

Okay, what good are these evaluation criteria. I think there's two purposes for them. One is to look at and development of state policies. So, if you're looking at different resource portfolios, different resource scenarios, you have a set of criteria you can evaluate those. And you can come to decisions as to do we want to encourage a higher level of renewables under RPS standards. Do we want to encourage a higher level of energy efficiency. Do we want to facilitate Mexican generation located south of the border.

All of these issues that the state has adopted some policies on and will undoubtedly adopt some more policies in the future, once you have a clear evaluation matrix then you can evaluate these side by side and see the benefits and disadvantages of each of them.

And then the second one is the one that's probably more pertinent to what we're talking about today is to use it to view resource options. Should I build this transmission line here. Should I look at a generating alternative. Should I look at a demand or energy efficiency alternative. How do those three things stack up from a cost, risk, environmental and other perspective.

So that's the purpose of the evaluation criteria.

The process that we talked about briefly in the May 19th meeting is first we interviewed stakeholders in California. And we tried to interview as diverse a group as possible. And we ended up talking to approximately 30 individuals at 22 different entities. And those entities are listed hopefully at the end of the presentation in attachment A.

From them, we didn't go with any preset notions. We said, you know, in terms of providing statewide resource planning criteria, helping us build the infrastructure that will be necessary in the next 10 to 20 years, what criteria do you think are important. What factors do you think are important.

And then the second step to that is how would you measure those factors. You could have a factor that's very important, but if you don't have any way of measuring it, and I'm not just talking about quantitatively, but also subjectively, if you don't have any way of comparing it then it's of less value.

We presented that information in the May 19th workshop. We received some public input at that time; and since then I've assimilated that information and in recommendations regarding some criteria, I think, that should be considered in a framework.

Now the caveat here is that I'm not giving you this as a prescriptive formula and saying you need to consider these five criteria; you need to weight them this way; and you got to exclude everything else.

I'm saying these are five criteria that seem to make sense to me, but depending on the study you may or may not need those. If you're looking at a small study, for instance, that looks at serious capacitors within a single zone, you don't need to perhaps do a large study that you might to do for an interstate type of transmission line.

So I need to emphasize, you know, I'm encouraging flexibility with this framework. And in the end, the analyst, the decisionmaker, the stakeholder decide what's the appropriate way to look at it and evaluate it. But I think it's good to have some ideas to start with and a framework that can be expanded.

This gives you an idea of the stakeholders that we surveyed. We talked to the PC, the Cal-ISO, various consumer groups such as TURN, environmental groups such as NRDC, several of the private generators, all three of the investor-owned utilities, multiple and municipal utilities such as LADWP, SMUD, renewable groups, transmission owners such as TransElect. And again, these are all listed in attachment A.

Again, the purpose there is to reach out, not to just people that are traditionally involved in this and have a certain level of expertise, but people that have a viewpoint and were accessible to us in order to interview.

Okay. There's a lot of statewide policies that have already been set. And one thought process is well, we can use these criteria to reevaluate those. That wasn't the focus of this. I called these policies that are already in place minimum criteria. And assumed that any scenario going forward would meet this minimum criteria and that we'd look at options that didn't involve mitigating or changing some of these minimum criteria.

So for instance, there's an exhaustive list of reliability criteria. That's set at the national level. It's set at the WECC level. California ISO has some additional reliability criteria. Some of the utilities have criteria on top of that just to operate their utilities in particular load pockets.

For instance, with respect to a planning reserve, when I talked to LADWP, they plan for a 15 percent reserve on a peak hour of one-in-ten. Now, that's different from most utilities. Most utilities will look at a one-in-two, 50 percent probability of exceedance for their planning reserve. L.A. takes a more conservative stance. So that's on top of all the other criteria that they have.

I accept all these as minimum requirements. Any scenario or alternative we look at needs to be in accordance with that.

There have been energy efficiency standards set by the state. There have been demand response programs and standards set. Same thing with renewable portfolio standards and resource adequacy. So instead of trying to provide an exhaustive list of all these standards, I'm trying to present this as a concept. There are standards, minimum requirements in place that the state has adopted or the utility has adopted and these in other areas.

Okay, the feedback we received from the stakeholders I thought was convenient to categorize in these four areas. And there's a lot of cross-over, as you'll see. There can be least-cost criteria that are considered environmental and so on and so forth.

But generally I looked at reliability; in other words, what did the stakeholders suggest. They said I need to focus on the reliability of the system. And they gave me some possibilities for that.

Least cost. Least cost means a lot of things to a lot of people, and I'll review that a little bit. But there's a lot of lease cost criteria.

Risk criteria and environmental criteria. In attachment B to this presentation you have where I summarized the notes from the various participating entities and the criteria they suggested.

PRESIDING MEMBER GEESMAN: Eric, let me ask you to reflect for a minute on the difference between the conservatism of Los Angeles, for example, using a one-in-ten criteria. I believe they utilize a similar one on their generation side. Versus the practice among the investor-owneds and, for the most part, state government, to utilize a one-in-two.

Is that principally driven by Los Angeles' historic policy of self reliance? In other words, if you expand over a larger control area, or larger pool, is there a ratonale for a less conservative reliability criterion?

MR. TOOLSON: Certainly reserve sharing

generally drives down the reserve margin. But this isn't necessarily an economic comparison. Reliability standards aren't economically set. They're set as arbitrary standards that -- I shouldn't say arbitrary standards -- they're set as standards that experts in the industry over the years believe best represent their system.

Now, Los Angeles is adopting a more conservative standard than that. There might be a lot of motivating factors there, but it also might be that for a municipal, you know, the cost of an outage, political and otherwise, is so high that it warrants being conservative. And more conservative than perhaps other entities.

And so I'm just speculating on that.

PRESIDING MEMBER GEESMAN: Thank you.

MS. JONES: Can I ask a related question.

PRESIDING MEMBER GEESMAN: Please.

MS. JONES: And this might be something that we'd have to look into in more detail. Is there anything in particular about the resource mix that LADWP has that would drive them to a one-in-ten versus a one-in-two?

MR. TOOLSON: It could be. They're

composed of very large generators, and don't have much of a diversified mix. And obviously you'd rather serve your load with a lot of diversity, a lot of different resources. If you have several large coal, pump storage or other facilities, that may be important.

PRESIDING MEMBER GEESMAN: I'm going to give my friend, Randy Howard, a chance to interject here. Randy. You need to introduce yourself for the court reporter.

MR. HOWARD: Randy Howard, Los Angeles Department of Water and Power. I just can't sit back there much longer.

(Laughter.)

MR. TOOLSON: Well, I hope I wasn't too far off in my speculation.

MR. HOWARD: No, you're not. Our reserve is actually closer to 20 percent. And they were very good questions coming out. We are more conservative in approach. We do take a one-in-ten.

But the other thing, it is true that it's based on our largest single contingency, and that's our Intermountain Power Plant. And with those units being 980 megawatts -- and I'll talk a little bit later about an event that did happen last Friday while we were going into our single largest peak when those units went down, and why that contingency is so important to us and that reserve versus what another utility might utilize.

PRESIDING MEMBER GEESMAN: Thanks very much.

MR. TOOLSON: So it sounds like we can downplay my political theory and consider resource magnitude.

PRESIDING MEMBER GEESMAN: Not necessarily.

MR. TOOLSON: Anyway, those are the four categories. Now, let me talk about what some of the stakeholders suggested in the way of reliability criteria.

And as I bring these up last time I just spoke about what they suggested. This time I'm going to comment on them a little bit so you can see the path I'm trying to weave before I get to the recommendations.

So, one of them, of course, is minimize unserved energy. Unserved energy is a very undesirable outcome. And if we can minimize unserved energy between alternative portfolios or resources that's a good thing. And it is.

There's some concerns with that, though. One is if you're already considering least cost, and you put unserved energy in as a cost, it's being considered. And by bringing it out again, perhaps you're double counting it.

Second, in our simulations, and my experience is of having done this three times with various lines, you're not getting much unserved energy. You know, the problem is the models, the way they're set up, you have perfect foresight on the loads; there aren't a lot of unexpected conditions; and in fact, the ones that I'm familiar with on the Palo Verde-Devers and Path 26, and also a recent study in San Francisco, there was no unserved energy, zero unserved energy except in Canada where we probably had a little mismatch between the resources available and the hydro profile. So that's the other problem. It's not a very telling criteria.

And then the third is we're not considering a great part of what causes forced outages, you know. We have generator-, transmission- and distribution-caused outages. Of course, we're not considering distribution at all.

And we're also not modeling transmission forced outages.

We are modeling generation-forced outages. Why is that? Well, and there's probably a lot of power system engineers that understand this better than I do, if we used an algorithm called the DCOPF we're using something called power distribution factors. In other words, how's the power split up at every node. 14,000 of those nodes in WECC.

That has to be recalculated every time the transmission configuration changes. So if you want to pull a line out for a single hour you need to recalculate that. Apparently that's a very time computationally -- very time intensive process.

And so state of art, as I understand it, with models is that no transmission outages are considered unless you do that discretely through scenarios.

So you're missing a big part of the unserved energy anyway, and that's one of the reasons it's zero. Very seldom do you have insufficient generation to meet your load. Particularly when you can wheel in power from

Montana to meet load in San Diego based on model results as long as it's physically feasible. So the concept is great. The application of that has some issues.

Minimize reliability payments. We've heard about that today. Some would argue that they're included already in total costs; so you don't need a separate line item as to how far did you knock the RMR payment down, how far did you knock the MLCC payment, because they're in the total cost.

And from some issues these costs -- and this is the second bullet there, it's kind of a discussion on its own. If you look at it from a societal perspective, and Joe talked about looking at it from different perspectives, an RMR payment may just be a transfer payment. It may just be money from one group to another but doesn't affect social efficiency. I'll just have to leave that point there without going into a lot of detail on it. Just to say that there's some discussion as to whether that's really a social efficiency or not.

Third one --

PRESIDING MEMBER GEESMAN: I need to

add, though, there that both FERC and the CPUC have expressed a substantial hostility to RMR payments, or RMR contracts and RMR payments. And I think as a matter of established both federal and state policy, whether that's considered a transfer payment or not, it's not considered something that we want to encourage.

MR. TOOLSON: Okay, and I agree with that. And it certainly is a participant payment that has a big impact on the various participants.

The last one is also a very notable goal, which is to minimize potential terrorist consequences. Since September 11, 2001, this has been an important planning item. How do you do that? What can you do to minimize the consequence at the single location causing widespread outages and so on.

The challenge there is most of our resource plans aren't built with that consideration. And at the level we're doing it, the high level decision, that's more of a subjective consideration. And it's difficult to quantify. So those are some of the issues with the reliability suggested criteria.

Let's go to least-cost criteria. A lot

of these criteria have been around for 30, 40 years. It's now resource planning stuff. Present value of cost or revenue requirement. Compare that to the benefits. There's different approaches there. Do you use capital cost as your decision criteria, or do you use present value revenue requirements.

When I talked to one of the IOUs in the state and their transmission group, they use capital costs. And they insist capital cost is the right criteria for investment decisions.

If you'll notice the Cal-ISO analysis, it was based on revenue requirements. Just an item there that would have to be clarified in whatever framework to use.

As we talked about today, there's different perspectives. You can do present value from society, WECC, California and subregional, Cal-ISO, utilities. Define your perspective.

Cal-ISO came up with a methodology called the modified cost. Modified cost excludes all generator profit from uncompetitive conditions. So in other words, they're not trying to maximize generator payment, they're trying to maximize generator payment from competitive conditions. A lot of discussion as to the validity and value of that. But that's the Cal-ISO's perspective is that it's the modified costs that need to be considered in investment decisionmaking, not just the direct costs, themselves, except at the societal level.

Third is typically everybody doing these studies agrees that everything you can quantify you put in there. Okay. And there's some planners that will say you really only need two criteria. You need to know what the expected cost is, however you get there, and you need to know what the risk is. And if it's an important criteria you try to quantify it.

You know, similar to Joe's statement, whereas if you don't try any quantification, you assume it's zero. And so, for instance, if there's environmental impacts you try to quantify them. You go beyond airborne emissions. You might try to quantify water impact. You might try to quantify land use impact, aesthetics.

So you put all of those things in, there's a lot of debate and discussion as to how to best do that, and what you include and not include.

So this is all present value. These are different variations on it that I received from the stakeholders that I talked to.

Some of the newer criterion, this is still continuing least cost. If you have a single asset, and you'll notice in the IOUs there are those that have come out, they use two terms significantly and say that's an important part of their evaluation.

One is market valuation. Put the estimate in and see what its value is compared to the market prices.

And the last one is the last bullet on the list, portfolio. So in other words, they take that asset; compare it to where their long and short positions are and come up with some kind of an index.

I agree those are valuable on a single resource perspective, but on a portfolio perspective, the portfolio changes the market price. And on a large portfolio perspective, also this concept called portfolio fit is, in my mind, less valid.

Other things they're looking at. Cal-ISO is looking at market efficiency. Market efficiency means two things to them. One is what is the ultimate price that you're forecasting for the market versus the competitive price. Look at that ratio. We're supposed to be promoting a competitive market. How close are we coming with the infrastructure that we have in place.

The other part for market efficiency that's important to the ISO is sustainable markets. And you might find that kind of interesting, but the ISO recognizes that if you don't have a sustainable market for generators, it's short term in nature, and doesn't provide long-term infrastructure and healthy competition that you need.

So they'll look at markets and see if there's sufficient revenue in that market to justify generator entry and remaining in there.

Seamless markets. RTOs are focused on seamless markets. How do we make it so the west, as much as possible, is one seamless market.

Okay, so those are some of the other criteria that were provided from the stakeholders.

Risk criteria. You know, 15 years ago we did risk by looking at a couple of scenarios and that was the extent of it. And since financial trading came into place, we look at portfolio theory, we look at efficient frontiers, and this concept of risk is much more rigorous and well defined than it was back then.

If I were to say the one big change in my mind, as a resource planner in the last 20 years, it's just the progress and the evolution of the risk concept and how it's applied.

Okay, there's a couple ways you can look at risk. You can do it just from a visual inspection and a histogram. For instance, this is a histogram that the California ISO used in their Path 26 study. And what you can see is each of these -- so the probability that this project, and this is in 2013, could have lost money, actually caused system increase in production cost -- this doesn't have capital cost in it -- is 15 percent. And so on and so forth, and the sum of all of these is 100 percent.

And you can see from this, for instance, if this is your cost range from 10 to 20, you know, what's the probability that you're going to lose money; what's the probability that you're going to make money; and what are some of the tailend events that help to define the insurance value. So that's a histogram.

You can quantify results from that. Or you can just visually inspect histograms for various resource alternatives and look at the difference.

There's a downside risk. And you say, okay. For instance, this project it's impossible to lose money. On the other hand, you have another project where you might have a pretty long tail into the negative benefit area. That's an important consideration.

On the upside, and this particular histogram doesn't illustrate it that well, you may see little pockets of benefits out there to the extent that you've been able to model extreme events. Those represent an insurance value. I'll talk a little bit more about it; it's not the entire insurance value, but conceptually helps you understand that if you get high gas, high load growth, low hydro and high markup the system costs are going to increase dramatically, but you might find you have a $300 million benefit from that line in that particular case. So it helps you understand how it's going to be mitigated.

Let's go back to where we were before.

Some people will say I'm going to do it a little bit in an old fashioned way, if I figure hydro's my biggest area of concern I might run 100 hydro cases. Each of them have equal probability of occurrence. And I might just take the ten worst cases, average them and that's going to be my average worst case. I'll look at the difference between the average worst case, and the expected values, and that's how I'll measure different portfolios.

There's a lot of discussion and thinking about various portfolio theories. Value of risk is an important concept. And that's modified for utilities, for people holding liquid assets.

The challenge with those type of things is that you need a market price. You need a market price as an input and you need to understand volatility and correlation on that. That's really an output in a transmission study. You don't start with a market price because the transmission line impacts market prices at both the receiving and delivery end.

And so it's very hard to run enough scenarios to crank out enough prices and valuation to do a robust portfolio theory. And I'll talk a little bit about the tradeoff between transmission studies and what the economists would like in the way of statistics.

There's a lot of other risk on the project level. There is a CO_2 regulatory risk. And I believe that's been adopted by the PC that that needs to be considered now. And that can be considered now a least cost, or it can be considered a risk.

Resource diversity. NRDC, for instance, suggested that it was important for them risk-wise to just prepare a simple pie chart. And in that pie chart just see what fuels are providing the energy. And they can compare scenarios pretty quickly and understand resource diversity, fuel diversity, environmental impact and those things. And so that was their suggestion.

Resource flexibility. Give you an example. Two transmission lines, both coming in at the same time. If one line, you have an opportunity to step off after the permitting/ licensing process, if it doesn't look as attractive anymore. That would have value over one where you made an initial commitment and didn't have any flexibility there.

The last one, California self sufficiency. Now, I can't remember right off who gave me that. That sort of is the opposite of the seamless market. And in their mind California needs to develop self sufficiency. They need to be able to meet their own load without relying on imports from other states. And that was an important criteria for them.

PRESIDING MEMBER GEESMAN: You didn't speak with Loretta Lynch, did you?

(Laughter.)

MR. TOOLSON: I did not. She might have declined my interview request.

PRESIDING MEMBER GEESMAN: You may have channeled her on that last one.

(Laughter.)

MS. JONES: Eric, can I ask you to go back to the portfolio theory and give a little bit more explanation of the TEVAR approach.

MR. TOOLSON: Okay. All of these are family of value at risk, VAR, right. And VAR is the one that came up with Morgan Stanley in the mid '90s and they published their approach and provided the ultimate numbers for it.

PRESIDING MEMBER GEESMAN: Morgan

Guarantee, I believe.

MR. TOOLSON: Oh, is it -- okay. Since then for utilities they realized that we can't cash out of our position instantly. It's not a liquid market. We can't sell our obligation to meet load 20 years from now on today's market.

And so they developed something where you actually consider these illiquid assets in a way that you take them to completion. You're not just forecasting the price into next year, you're forecasting the price 20 years out.

And that's a problem because if you do it in the next year you can rely on the forward market. There's good market pricing and there's a lot of volatility and correlation data. If you go out 20 years you have to develop those pricing and the volatility for it.

Okay, but that's how they'll do it, in more a cash flow at risk where you look at the delivery.

Now, TEVAR is something I'm less familiar with. But I think it's similar to cash flow at risk. And I believe the suggestion from the PC and perhaps there's somebody from the PC or CEC that can clarify that, is that they'll look at a 12-month rolling average on their exposure, on their value at risk.

And value at risk just means that for a certain confidence level, this is your worst case outcome. Now, getting that short term in nature, and we're doing long term here. So, --

MS. JONES: Thank you.

MR. TOOLSON: -- I don't know if that answered your question, or I just talked long enough that you forgot it.

MS. JONES: No, that's good enough for now, thank you.

MR. TOOLSON: Okay, I think I need to move a little faster here. So I'm going to go through some of these pretty quickly.

The environmental criteria, a lot of these you've seen before, airborne emissions. One entity suggested they want to see different alternatives. If there were, in fact, one that had an accelerated renewable portfolio standard that should be recognized.

Los Angeles, again now I have to be careful what I say about L.A. because they have a representative here -- but I believe this is correct, that Los Angeles has a policy that they won't build any new transmission line until they fully utilize their existing right-of-way.

And why they don't do that is they recognize there's a lot of visual impacts, aesthetic, perhaps concerns about magnetic fields, there's a lot of cost to acquiring a new right-of-way that doesn't appear just in the direct land cost. And so this is their way of dealing with that information.

And so here's where we go beyond environmental. Your question is can you consider any other environmental factors in resource evaluation. You can, you just have to make assumptions as to the value of water, the value of aesthetics and things like that, which are tough to grapple with right now.

Okay, fossil fuel dependency. We talked about water impacts. We mention environmental justice assessment. There are probably three or four entities that were very motivated to see that this be considered in some way or another. And I talked about this example last time, so I won't spend a lot of time on it.

But one way you can analyze various resource plans, and try to assess their environmental justice assessment is you can develop something like this. And all we've done is we've taken the 3000 zip codes of California, distilled them down to about the 60 zip codes that had generation built in those. And then categorized those in the bins.

And so, for instance, we have low income zip codes. Now, you might say, okay, if generation's being built in the low income zip code, that's not a good thing. But on the other hand, we thought well, you need to consider also the population impacts.

So you look at this and this just happens to be some CEC data that we used for the last five years. It's not meant to draw any conclusion, but just be illustrative. You can say, for instance, okay in income level two I see probably my greatest amount of generation across almost all population levels. I don't see it much at 5, less at 4 and so on.

And from that you can draw sort of a surface map that will help you understand, okay, this is the impact to this particular resource portfolio. You wouldn't do an environmental justice statement for a single plant, but you would when you're looking at policies going forward. So that's an example of that.

Let's talk about proposed framework. Okay, these are the factors I took out. And I took them out thinking that this isn't something rigorous, you know, this isn't something where I'd say use these. You'll notice I never apply a weighting to these. The decisionmaker needs to apply his or her own weighting to those.

I'm saying I think it's important that you consider reliability, but I'm going to tell you how I think you ought to consider reliability, and it's not unserved energy or reliability standards or anything like that.

I think it's important to have some framework for least cost. Any way you define it, any way you think it's important for your utility. If you're a utility you might want to look at this ratepayer impact. If you're the state, you may want to look at all California participants. You define it for the study you have in mind.

Risk. I think it's important to do risk. Now, I wouldn't say you have to do this all the time. There's some projects where the basecase, you know, maybe on a series capacitor, is far in excess of -- the benefits are far in excess of the cost. So I'm not saying you do this for everyone of the studies. But for the most part you need to consider risk and use that in your evaluation.

Then these other three are three that I thought were important, but in fact, when you're doing these studies for your own entity, organization, you come up with the factors you think are important.

From a statewide level I think market efficiency is important. It could be market efficiency/sustainable market. But some indication on the market, I think, is important.

Fuel diversity, just from a high-level statewide policy, NRDC's suggestion of looking at it in a pie chart or something. That seemed to me to be a good consideration. And then resource flexibility, if there's a big difference in resource commitment, budget constraints, those sort of things, of course they'd have to be taken into consideration, as well.

So I go ahead, and you'll notice on the right-hand side, the middle column is some indication of how you measure it. As I mentioned before, if you don't have a way to measure it, it's not that helpful.

I'll give you an example. Tons of uncertainty with market paradigm, difficult to measure. First of all, it's hard to model. You try to model a hybrid market with LNP in California contract elsewhere, that's a very difficult assignment. Second, it's hard to put a probability on it. So, you know, those are -- that's an example of a variable that's pretty tough to quantify.

Least cost. This is a computed one. You can see there's also three subjective variables in there. You know, I don't know of a good way to do reliability. And reliability, I'm just saying is there are differences between the two plans.

So, for instance, I'm involved with California ISO now looking at a transmission line into San Francisco. Now, we could run the generation in San Francisco more and not have a transmission line that crosses the Bay. That's one alternative and it meets all reliability standards.

We could have another alternative where

one crosses the Bay, reduces generation in San Francisco, and you might say let's assume they're equal in every other factor. Well, the truth is the one that crosses the Bay provides you with a second corridor in case of an outage, okay. That's not reflected in our current reliability standards.

Those are the sort of things I bring out here. Subjectively describe the reliability improvements, if there are any, between alternative resources.

Risk. Do risk however you want to do it, but just do it objectively and do it across. I mean, I'm trying to come up with a methodology that if you're a one-person planning department for a small municipal and you have maybe half time to do this in a month, that you can come up with something. That you wouldn't just throw your arms up in the air and say, this is impossible.

My experience with the California ISO studies is that on the level of study we did, these were a minimum of five- to ten-person months. Okay. They were a big effort. It's not feasible to assume that every planning entity can do that.

So you might just do a standardized worst case and look at it. You might run 100 cases. In the transmission planning business my experience is that it's pretty tough to run more than 20 cases for two years.

Okay, look at the scope of what the ISO did. Seventeen market-based cases for two single years. That took a lot of time, you know. So, when people start saying this is where the divergence occurs between the economists and the production costing people, the economists want hundreds of scenarios, thousands. In certain places you can do that. If you have a price curve and you know all the volatility, you can just crank out Monte Carlo simulations all day long. But a transmission study, that's hard to do. And I'll talk a little bit about that in my second presentation.

So those are my five criteria that I'm suggesting you consider. Obviously you need a least-cost criteria. Generally you're going to need a risk criteria. If reliability, if there's some differential between the two, you want to consider it. If there's differential in efficiency, fuel diversity and resource flexibility you'd want to consider that, as well.

Okay, conclusions. We've talked about this framework needs to be flexible. You can look at some preliminary economics, if it's strongly economic or uneconomic there's probably less need to do a lot of sensitivity cases. Project scope, if it's series capacitors versus interstate line, that's going to be a big difference in the level of study you need to do. And last, the resource is available.

Okay, any questions? Okay, let's go to the next one then.

PRESIDING MEMBER GEESMAN: Eric, I think I'm going to interrupt you because we've got a commitment to a couple of entities to get them out of here before 12.

MR. TOOLSON: Okay.

PRESIDING MEMBER GEESMAN: So, this might be a good time, Don, to move to San Diego.

MS. GRAU: Okay, to accommodate the folks from SDG&E and IID who need to catch a flight we're going to skip now to part two; we're going to skip beyond the staff overview and go directly to SDG&E's presentation.

MR. AVERY: Good morning and thank you.

My name is Jim Avery; I am the Senior Vice President for Electric Operations for San Diego Gas and Electric Company. And I did hear some questions this morning that got into discussions of RMR, and I actually am prepared to answer those questions for you if that would be of help.

I'd like to thank you for giving us the opportunity to speak today and for accommodating our schedule. I guess I misread the agenda when it came out and I thought I was on at 9:00. So, I'll try to go through this quickly because I know you have a lot of speakers here today, and I'll try to focus on some of the things I heard this morning. And if there's any area you want me to stop and elaborate on, please do that.

At San Diego when we look at transmission we look at total integration; we look at what we need to do to satisfy our customers' needs. And we start out trying to look at it from a balanced portfolio standard.

In 2003 we issued an RFP to satisfy our grid reliability requirements. Essentially when we looked out into the future, and I'm going to take you back actually to 2001. We had proposed building a transmission line because we identified a transmission deficiency on our system starting in 2005.

The transmission project that we proposed was the Valley Rainbow project. I know you have probably heard of it, and you have probably complain about that on a number of occasions. But there was the transmission project that was going to link our system with Southern California Edison; provide another transmission corridor into San Diego at a relative cost of about $340 million.

Had it been allowed to go into service in 2004, as we had requested, it would have saved our customers in RMR costs from the MLCC side, as well as just the fixed option payment equation, about $191 million in the first two years. I can't say enough how important transmission is for us.

Taking us, at the same time period, 2001, we saw a significant jump in generators that wanted to locate in the San Diego region, in the border generation region. San Diego identified the impact of that, working with the ISO. Moved forward to build the necessary transmission to mitigate congestion on our system.

Unfortunately it took us three years to permit putting a transmission line on an existing right-of-way. That was the Miguel-Mission number two project. Fortunately, a good part of that project did not require a certain number of regulatory approvals. We could do the transformer addition within existing substations. And that allowed us to move forward and get the transformers in place by October of last year, which did mitigate a significant amount of congestion on our system.

Prior to the transformers going in place, the amount of energy that we could move across the southwest paralink was roughly capped at about 1000 to 1100 megawatts. The transformer increased that number to about 1400 megawatts.

With the addition of the Miguel-Mission number two line we've improved that transfer capability to about 1900 megawatts.

At the time period that we started the 2003 RFP we looked at what we could do to improve our energy efficiency demand response programs; looked at securing renewables; and also looked at generation alternatives; and left last on the list transmission.

And the reason for that had to do with just the sheer magnitude of the effort to permit transmission and some of the things I'm going to show you in just a few minutes as to what bottlenecks do we face when we look at building transmission.

PRESIDING MEMBER GEESMAN: Do you have a sense of what you expended on the Valley Rainbow permitting process?

MR. AVERY: I know that number all too well. It was right about $20 million to permit those facilities. And we actually did not, unfortunately, get past the need phase of the project.

The ISO determined the need and verified the need early on. But, as you know, we got lagged into the political process of nobody wanting transmission built in their backyard.

I'm going to jump ahead and just focus on the transmission-specific issues. Miguel-Mission is the yellow dashed lines you see on the presentation here, essentially putting a 230 kV circuit in an existing corridor between our Miguel and Mission substations.

When we identified the fact that our

congestion costs were skyrocketing, we looked at ways that we could accelerate this project. And we came up with some pretty creative ones. Essentially the line is not complete yet; it will not be complete until next spring to summer. But we have energized a 69 kV line at 230 kV for the first 12 months of this project.

Portions of the actual 230 work are completed already, but there's a significant gap where we have energized a 69 kV line at the higher voltage level to buy us time and to mitigate congestion.

You saw the estimates this morning that suggested the inc'ing and dec'ing effect of not having or having this congested corridor created between a 12- or 13-month time period of '03 to '04 of about $32 million. Well, actually over the last 12 months that number climbed closer to $48 million. If I look over the next 12 months from this July to next June when the Miguel-Mission project will be finished, that number is far in excess of $50 million had we allowed it to go unchecked.

The projects, as I look into the future, that we have been moving forward with to also deal with congestion issues, in the San Diego Basin there are two power plants essentially, and a number of small qualifying facilities and a number of small generators.

But the two power plants essentially are 50 years old, or 50 years plus. Some of the units have been installed as recently as 31, 32 years ago. But that's essentially the newest of the fleet in the San Diego region.

As a result of that the heat rate of operating those machines are at 10,000 and above. And, in fact, one of the larger units, South Bay 4, has a heat rate that probably approaches 14,000. Yet that is the unit that is quite often relied upon by the ISO to satisfy what we require as the MLCC, the minimum load carrying side of the equation.

To mitigate that, San Diego, in its 2003 RFP, signed contracts to have the Palomar Energy Facility constructed; and San Diego will take title to that facility in the beginning of next year. And we also signed contracts with Otay Mesa or Calpine to have that facility constructed.

These are new state-of-the-art, combined-cycle technology; heat rate at the 7000 range. And with gas prices that we were looking at just three, four, five months ago, and suggesting how could they stay at $5, we're now looking at this winter being $8 to $9.

And when you talk about heat rates of 10,200 to 14,000, and relying upon that energy to satisfy our requirements, I think it tells us very quickly why the new generation is needed, and what transmission can actually do for us.

2008, if I look at 2008 we are looking at the Otay Mesa or the Palomar Plant already being online. The Otay Mesa facility coming online. And the additional transmission that's associated with that.

One of the questions you asked this morning was could we prebuild transmission to accommodate additional border generation. Well, essentially that is what the Otay Mesa project does. The Calpine generation facility is a border generation resource.

And in order to integrate that into our system it does require additional transmission. Otherwise it is generation that sits at the other end of a congested line.

As I look at our next major transmission project, out in the year 2010, even with the additions of the new generating plants that are coming online in 2008 and 2006, we're stuck in a situation where we do not have sufficient local generation, when you add on the import capability into San Diego, to satisfy our peak load requirements.

As a result of that, we need to look at another transmission link into the San Diego Basin. And I'm not going to touch on some of the things you heard this morning about the notion of transmission has other benefits, such as if you lose a corridor. We're in dire straits if we lose a single transmission line.

This morning we have two 138 kV lines that go to southern Orange County; serve about 35,000, 36,000 customers. After the recent rains we had this past year we lost a number of the footings beneath the single 138 kV corridor that we have going up to Laguna Nigel. We were doing some temporary repairs while we try to get permits to fix these structures permanently. We had taken one of those lines out of service; we lost the second line; and we lost the whole city this morning.

This is what we face every single day. We have to weigh the question of do we take a line out to try to repair it. And if we do, we're sitting on one other line. And if we lose that line we can be in a blackout situation.

As we look at the next 500 kV link into our system we think we can justify this on reliability because it's needed just to satisfy the growing needs of San Diego. And by the way, in our long-term forecast the South Bay Power Plant is sitting on land that belongs to the Port on a lease that expires in 2009. And keeping in mind, these assets, these generating plants were installed at that point in time 55 years ago plus.

And the second power plant, the Encina Power Plant, is also in the same category, from 30 to 50 years old. We're depending on that power plant remaining.

If we assume that it's going to go away, not only do we need to have this transmission line in 2010, we need to have one or two more combined cycle power plants built in San Diego. And, again, nothing has happened in the way of trying to permit those facilities, trying to locate those facilities. And we're sitting here doing what we can to get the transmission in here. But, I'll tell you, we can't go through what we went through with Valley Rainbow. If we do, our future is beyond uncertain.

So the reliability benefits. The reliability benefits are here -- and I'm going to just jump to the numbers -- 2010, we have a deficiency of about 333 megawatts. That's again assuming the Encina Power Plant continues to operate.

In 2014 the number grows to 700 megawatts. We're growing at 100-plus megawatts a year. And we need to be able to satisfy that growth. If we assume any of these power plants go away, we have to start putting in peaker units and another baseload plant to accommodate that.

The access to renewables question. San Diego, take us back three years ago, had less than 1 percent of its portfolio on renewables. When the state came out with the direction to be at the 20 percent by 2017, San Diego stepped up very aggressively. Today, just a couple of years later, we're at 5.7 percent. And we're negotiating contracts that potentially could put us at the 20 percent target by 2010. But we cannot do that without the new 500 kV line.

We have literally signed virtually every contract for renewable resources that has come to us in the San Diego Basin. And yet with that, and the resources we've been able to sign outside, we're still below 6 percent.

As we look into Imperial Valley, the region east of us, they have thousands of megawatts of potential, of wind resources, of solar resources, of geothermal resources. And, as such, we think the direction that we're going will give us the reliability needs, but also satisfy our need to bring in additional renewables.

Then the last leg of that stool was the question of economics. Can we economically justify a transmission line. Well, you heard a little bit this morning about the notion of what RMR costs are doing, and what does it mean for us.

Let me take you to, had we done nothing, we not put the Miguel-Mission line, not done the Palomar facility, not contracted with Otay Mesa, and do not do the transmission project in 2010, our RMR costs would be approaching $350-, $400 million. Just to maintain the older power plants and do what we can, piecemeal, to hold the system together.

These numbers, by the way, are at gas prices of $5. If we use $8 gas prices, you can add another $200 million on top of that.

So, from an economic standpoint, the savings in RMR, the savings in congestion costs, the access to renewable resources, the project will pay for itself without a doubt.

You heard some discussion as to where we're thinking of going. We know, we tried going north. It didn't work. The only other option for us is east. And if we go east we look into Imperial Valley. Imperial Valley is rich with natural resources from a renewable standpoint. We do have a link into the Imperial Valley area where there is a significant amount of generation that has already been built in the Mexico side of the equation.

While all of that generation today is deliverable across the southwest power link, to the extent that we had another access to that area we can bring renewables in from that link and with those renewables we can also shore up capacity.

So while the transmission provides reliability benefits, provides us access to renewables, it also provides us access to capacity. And it's the three of those pieces that we need to satisfy our growing needs.

I want to show one last thing. This is a constraint map of San Diego. The picture here doesn't do it justice, but virtually everything that's circled or colored is a special interest. Whether it is an Indian reservation, whether it is a military base, whether it is a national forest, whether it is a state park, San Diego has about 200 miles of border that limit us from the neighboring counties.

Out of those 200 miles, roughly 186 of it is protected by special interests, leaving about 14 miles of open access for us to get outside of the county. If we don't have the ability to -- and by the way, those 14 miles are tied up with homes. So, there are people living there.

If we don't have the ability to go across state land or federal land, we will not have the ability to bring transmission into San Diego.

Thank you. I'm prepared to answer any questions you might have.

PRESIDING MEMBER GEESMAN: Thanks for your presentation, Jim. I certainly hope that you have not ruled out continuing to try to access a northern connection, as well. I agree, you've obviously had some difficulties with that, but I would think that over time it's something that is quite important, both to the region and to the state, as a whole, to better interconnect your part of the state from both the east and from the west -- or both the east and from the north.

MR. AVERY: You raise a really interesting point. We absolutely believe someday we have to go north. And to be honest, the real benefits of the northern route are to the state moreso than San Diego.

We're sitting in an area where the import capability into San Diego on a non-simultaneous level is about 2500 megawatts. If I look at the local generation that we're adding, and I add in the qualifying facilities, and I forget about the old power plants, South Bay and Encina, that gives us somewhere in the neighborhood of about 1800 megawatts, which should be baseloaded.

I add on top of that 1800 megawatts the

2000 megawatts that can flow across the southwest power link, and I'm at 3800 megawatts that can come into the region with just the existing assets from the east and local generation.

And if I look at that as potential to good economic resources, this path providing access to Arizona. You heard about some of the economic benefits of having that generation there, and the benefits to California.

So the question is that energy has to either be absorbed in San Diego or be able to move north into Southern California Edison. Well, our only tie with Edison is through San Onofre. Well, when San Onofre Units 2 and 3 are running, the amount of additional energy that can go across that path is limited to just a few hundred megawatts, 300, 400 megawatts.

So if I have 3800 megawatts that want to come into our basin, and by the way, if I add a 500 kV line maybe bringing that to 4800 megawatts, and our average load is about 2500 megawatts, they want to move, the system wants to move over 2000 megawatts north, yet it can't.

So, while we're looking at what we can to satisfy our requirements, we also look to what the state can do. And if we lose that opportunity we'd be making a huge mistake.

I talked a little bit about the Miguel line that went into service. That effectively allowed us to bring in at the Miguel substation, last Thursday, over 1700 megawatts. If I look at that same time last year we were taking less than 1000 megawatts. Imagine what last Thursday would have been like if we had taken 800 megawatts out of the equation.

PRESIDING MEMBER GEESMAN: Well, I think you hit a sore point, because one of the things we seem least capable of doing as a state is taking a broader perspective than an individual service territory. Hopefully, we can improve upon that. But I think we have a fairly sorry record to date.

I also want to commend you for your company's performance and commitment to the state's renewable portfolio standard. We have made a very important priority of that, and it's pleasing to see the degree to which your company has responded.

I think that creates an obligation on the state's part, as well, to address the transmission roadblocks that may prevent us and you from achieving those targets. And, again, I would point to a northern connection, as well as the eastern connection.

The State of California has attached a great deal of priority to developing the Tehachapi wind resource. In this proceeding we've heard a fair amount about geothermal resources in Nevada and on the eastern side of the Sierras. We've lost an important device that we had expected to be able to utilize in FERC's denial of Edison's renewable trunk line concept. As a consequence I think that it's even more important for us to move forward on better interconnecting all regions of the state.

And I think that a northern connection between your company and the Edison system would better facilitate the development of some of those renewable resources that we attach such importance to.

MR. AVERY: I think it will perhaps provide the opportunity to move renewables through San Diego from the Imperial Valley region. If I look at Imperial Valley, and I look at our 500 kV project, as I said we're about 5.5 percent, 5.7 percent renewables today. With that 500 kV line we can be and will be at 20 percent or above in 2010.

If we look at the full potential of what we can do with that 500 kV line in conjunction with the southwest power link, and the renewables that are available in Imperial Valley, there's nothing to stop us from going from 24 or 25 percent up to 30 percent renewables.

Now, if you look at the north, how do we get to Edison's service territory? The southwest power link alone provides access to us at a 500 kV level. We looked at the Valley Rainbow corridor and we were stopped in our tracks. And essentially the land that we were looking at has now been taken into federal trust by the Pechanga Indian Reservation. And that no longer is an option for us.

There is one project that has been talked about since oh, at least five or six years, and probably longer, and that's the LEAPS project. LEAPS first came to San Diego as a proposal to construction transmission to connect us to Edison in conjunction with the potential for a pump storage facility.

The problem when Enron first came to us

with that project, it wasn't economical. And we didn't think it was technically feasible. And from our standpoint we were precluded from actually pursuing it because it traverses a significant amount of federal land. And the utility has to pursue other alternatives before it can pursue federal land.

As I understand, there is some legislation that is being pushed back and forth in Washington to potentially provide access through that federal land today. But I don't want you to think that that is going to be an easy project.

If you look at the potential route, it literally sits right on the spine of a significant mountain range, and goes 20 to 30 miles like that.

I mentioned this morning the issue of Talega where we lost one of our 138 kV lines while we were trying to maintain the second one that had some washout conditions. Imagine if you had 30 miles of a significant link that was sitting right alongside of a mountain ridge with the types of rains we had this past year. It would be a significant thing to try to maintain.

PRESIDING MEMBER GEESMAN: Well, and

that brings me then back to your first slide where you quoted from the Public Utilities Commission's December 04 procurement decision. And I see that they're encouraging you to consider the eastern line as an alternative for meeting a local resource deficiency by 2010.

Here we are again, back within the five-year Bermuda Triangle range of resource planning. And it is, I think, a painful deja'vu to the problems that were faced in the Valley Rainbow proceeding. Where my recollection is the Administrative Law Judge accurately summed up the positions.

The project proponents felt that a ten-year time horizon was most appropriate. The project opponents preferred a five-year planning horizon. The proponents said that with a five-year horizon, using the methodology then deployed, no project could be approved. The opponents suggested that using a ten-year planning horizon no project could be disapproved.

And as a consequence, the State of California is left with a just-in-time infrastructure policy where I guess we were debating whether the project should come on in year six or year seven.

I'm not certain that makes any sense at all for this type or this magnitude of project.

MR. AVERY: I absolutely agree. I mean, we're looking at a situation where the 500 kV line, our new project that we're looking at, if I look at what it could do for us right now in savings in RMR alone, we would be over $100 million of savings a year. You can build an awful lot of transmission facilities with $100 million of savings.

And by the way, that's RMR savings, that's not even tapping into lower cost energy. That probably produces another $100 million of savings right there.

But just RMR savings alone more than justifies these projects.

PRESIDING MEMBER GEESMAN: Well, earlier in these 49 days, I think it was probably day seven or day eight, I observed that one of your company's problems in dealing with state government was that you had a curvature of the earth deficiency. That from Sacramento or perhaps from San Francisco, we simply can't see you over the horizon.

Commissioner Boyd and I hope to correct that in this year's Integrated Energy Policy Report. I thank you very much for your presentation.

MR. AVERY: Thank you.

MS. GRAU: Okay, and since we still have about 15 minutes, if you think you can do it in about 15, okay. We will continue on then with a presentation by Frank Barbera of IID.

MR. BARBERA: Thank you, Commissioners, for adjusting the schedule to accommodate my schedule here for this afternoon. And also, want to thank you for presenting IID's views of the transmission challenges that we see here in the future.

I need to congratulate the Commission on its recent report where I believe it's captured, at least in southern California, all the transmission plans and everything very accurately in its recent issues and actions report here concerning the California electric system and the upgrades.

And it's going to allow me to keep my presentation here fairly short. Just to summarize our position today our transmission access is very limited. And it will not meet IID's future needs.

We do have four major interconnections to San Diego, to Edison, to Western and to APS at the present time. And as we look at it, we see a need for transmission. One of the other things that we also recognize in the IID service area, is that we have one of the best geothermal resources in the state, and there is other potential for other green resources in Imperial Valley.

Around the Salton Sea we do have a loop of transmission that can get these resources out to any of the four entities I previously identified here.

Now, in order to promote the transmission and to tie it all together we then, working with the various subregional transmission study groups, and as you can see where IID is involved we interface very actively with the ISO, with the STEP group, the SWAT group in trying to tie all of these together.

What's not there is, of course, the Imperial Valley study group, which has also been very helpful in promoting the green resources out of Imperial Valley.

What we believe, because of the large

region, western interconnect, that joint transmission projects are very much needed. And IID is very actively engaging many entities to do joint transmission. San Diego is a good example, as well as many of our friends to the east.

Now, historically that's the way in the west transmission projects were built. Also generation projects. This map represents in yellow all the joint lines that were built across the interconnect. We believe that that philosophy of continuing to build joint lines is necessary for the future.

And it's kind of interesting to note, I think this gives you a good visual impact of why that's necessary. The hundreds of miles that's needed for major transmission lines. You can see in the western interconnect, in the NERC interconnection WECC it's very very large. If you look at some of the smaller subregions back in the eastern interconnection MAAC is probably the size of the State of Nevada. So we need the joint transmission.

I do again congratulate the Commission for pulling together some of the base data for a good part of this. I do believe it's necessary to be inputted into the overall western interconnect, whether that will reside in WECC or any other entity down the road, in order to tie the rich resources that the west has, whether it be the coal in Idaho, the wind at Tehachapi, or Clovis, New Mexico, all together and bring it through a robust transmission system that needs to be continually enhanced throughout the western interconnect.

I believe capturing it all now, and we will get the economies of scale in this transmission line building and upgrades that need to be done, as well as in the development of larger plants, for instance larger geothermal plants in the west.

And basically that's IID's message here. If you have any questions?

PRESIDING MEMBER GEESMAN: Can you give us an update on IID's involvement with the Desert Southwest transmission project?

MR. BARBERA: We are continually -- we are involved in doing a technical evaluation and trying to further encourage that with even more participation. And so, you know, we want to be a stakeholder there, but we want to bring other stakeholders into the project, as well.

PRESIDING MEMBER GEESMAN: What do you see the timeframe being?

MR. BARBERA: Quite honestly that won't be until about the 2008, 2010 timeframe is my opinion.

PRESIDING MEMBER GEESMAN: And what do you see as the controlling events or controlling factors in establishing that timeframe?

MR. BARBERA: The actual needs and overall development, one of the ingredients would be the, for instance, geothermal development. To get the large-scale plants built so that that transmission could be utilized would be a need.

The other things that needs across the IIS system is agreements between say California and Arizona about what energy could be procured on a long-term basis to justify the financial impact on the transmission line, and the overall capacity that would need to be developed on something like that.

And we're working, we're addressing those issues. But we need to bring it together.

PRESIDING MEMBER GEESMAN: Thank you very much.

MR. BARBERA: Okay. Any other questions? All right, well, thank you.

PRESIDING MEMBER GEESMAN: Why don't we break for lunch now and reconvene at 1:15.

(Whereupon, at 11:47 a.m., the hearing was adjourned, to reconvene at 1:15 p.m., this same day.)

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AFTERNOON SESSION

1:26 p.m.

PRESIDING MEMBER GEESMAN: Hello, Pat. Yeah, just make certain that the green light is turned on on your microphone.

MS. ARONS: Good afternoon; my name is Patricia Arons, that's A-r-o-n-s for the transcript recorder. I'm with Southern California Edison.

It's difficult to be a visionary and doubly difficult to see problems coming. Therefore, I conclude that's probably why I'm not a Senior Vice President.

(Laughter.)

PRESIDING MEMBER GEESMAN: Yet.

MS. ARONS: I only have some comments to offer on the report and on the process. And before I begin I would like to share with you an event last week that I think is important. And one that we continue to grapple with in the transmission area.

Edison hit two subsequent days of all-time system peak on Wednesday and Thursday. And oddly enough during that period of time there was some rather wild weather going on in the Inland Empire.

And we had an event that we haven't fully diagnosed yet, but it appeared to be a fault on a 33 kV distribution network line out of our valley system that precipitated what we believe to be an air conditioner stalling event.

And the consequence of that event on this very hot day where the loads were at all-time highs was that the voltage at Devers dropped to well below 500 kV. It's probably -- I've heard on a momentary basis it dropped to as low as 478 kV. And that's pretty devastating on a hot day with high loads.

But there were a number of other things that happened to be going on on that day in addition. But it does highlight on a real-life basis the importance of the appliance standard for single-phase residential air conditioners.

And I know that Edison has been working with the Energy Staff on that process, so we do appreciate the Commission's efforts. And particularly, Commissioner Geesman, your interest in the problem. Thank you.

PRESIDING MEMBER GEESMAN: Well, it's a

problem that you warned us of last year. And I want to make certain as you complete your diagnosis of last week's experience that if there is action that you believe state government should take as a follow up, that we make certain that that's done in a timely way.

MS. ARONS: Right, really what -- I believe that what we need, and what I've spoken to this Commission about in the past, has been an appliance standard for single-phase residential air conditioners that requires an under-voltage trip mechanism on the equipment so that in the event that there is a stalled condition that it doesn't perpetuate itself up to the transmission grid. That's the action that we believe that we need.

With regard to the Integrated Energy Policy Report process we support the development of a comprehensive and proactive transmission expansion policy which includes a statewide planning effort to insure the development of a strong transmission network in California.

There is a critical need to improve and coordinate the planning processes for the siting and permitting of transmission in California. The

CEC Staff report is a major step in the right direction to develop such policy and coordination between the appropriate agencies; and SCE supports many of the proposals outlined in the report.

We believe, however, that it is also important that the proposals do not create duplicative processes that would further burden any transmission planning process that really is today becoming quite burdened for our engineers.

We believe the staff did a very fine job of capturing our input, drawing appropriate conclusions and identifying policy options. SCE wholly supports the development of corridor planning process and a need identification process that would allow stakeholders, agencies, landowners and other interested parties to collaborate, cooperate, discuss and resolve the issues associated with the corridor identification process, and the ultimate siting of transmission in the corridor.

SCE supports the creation of a corridor study group as outlined in the report. The proposal in the report to extend the time a utility is permitted to keep the costs of land acquired for future needs and ratebase is also meaningful and should be pursued.

Clearly the five-year land banking limit in existence today is not sufficient for the utilities to perform long-term planning, and adversely affects the development of transmission in critical areas of the state. We strongly encourage the CEC to work closely with the PC in establishing a proceeding to explore land banking issues.

We fully support the coordination between utilities and the planning alternative corridors for transmission, the PACT program, to facilitate the identification of transmission corridors and allow the public and decisionmakers to understand the pros and cons of the specific, proposed and alternative transmission corridors.

SCE looks forward to participating in the establishment of a policy advisory committee, and the technical committees proposed by staff as part of the PACT program.

We believe that the establishment of a biological database to assess environmental implications associated with transmission corridors will also help facilitate the timely development of transmission facilities.

The development of such a database could assist with the environmental assessment of those corridors identified in the corridor planning process, and could decrease the amount of time required for a utility to prepare an environmental impact report.

With a better understanding of where development in each corridor will result in the least amount of environmental impacts, the time required for transmission siting could be decreased, while conserving as much as the natural habitat as possible.

Any transmission line sited in a particular corridor would not need a separate environmental assessment. Instead a programmatic EIR could be created that is related to a specific corridor and not a specific transmission project. In fact, if you extend your thinking on that to a statewide programmatic process you can begin to look at environmental mitigation in total as a result of your corridor selections, your multiple corridors.

As CEC Staff summarized in its report titled, a roadmap for PIER research on biological issues of siting and managing transmission line rights-of-way, which was issued in April of 2004, transmission corridors are often quite long, which can affect several habitat types and species of concern within one corridor.

Siting new lines is often complicated and lengthy, as we've all heard today. And is also subject to public opposition due to biological, visual, real estate value and health concerns.

Strategies that identify opportunities to promote conservation while maintaining system reliability could contribute to statewide conservation efforts, reduce negative public perception, and facilitate the siting of new much needed transmission lines.

In the same report the staff proposed that the CEC explore dedicating Public Interest Energy Research environmental area, PIER-EA, funding to establish the tools and methods to facilitate the environmental assessment of selected or designated corridors.

SCE supports the staff's proposal and strongly encourages the CEC to reexamine the process and proposals related to an environmental database as outlined in the April 2004 report.

With respect to the integration of renewables, in the report the staff briefly addresses the impact that renewable resources and intermittent generation have on the operational reliability of the grid. SCE supports staff in their assessment that the integration of renewables will further complicate the existing frequency support problems on the grid.

We also support further research on the issue to better understand the operational implications associated with integrating large amounts of nondispatchable and intermittent resources in a safe, reliable, efficient and cost effective manner.

We believe that there are additional operational and planning costs that utilities may have to incur in order to integrate a significant amount of additional intermittent and nondispatchable renewable power.

The CEC's 2005 IEPR focused on this integration issue. And SCE supports the proposal in the staff report. And the CEC operational integration work actively initially undertaken by the staff continue through a collaborative effort. This is of particular concern to SCE because the majority of identified renewable and wind potential in California is located in or near SCE's service territory. This fact, coupled with the state's desire to significantly increase renewable resources creates a high likelihood that SCE will be required to integrate ever-increasing amounts of intermittent and nondispatchable resources potentially far in excess of our own obligations.

Two additional comments. Although discussed in the report there was a section about the importance of educating the public about the function of the transmission grid. And this is necessary, but also potentially something that we want to undertake very carefully because of the security concerns associated with putting too much information out into the public with regard to potential vulnerabilities on the grid. So we need to be very thoughtful about how to educate the public in a meaningful way, and yet not open up new possible vulnerabilities for ourselves.

The other area or comment that I have is transmission serves many functions. And the report focused this year, I think, a lot on generation, integrating generation, markets functioning and how transmission is developed in response to that. And perhaps next year we really need to give some thought to load and how load develops and where it develops in the future and how that can affect the grid.

I think that we're somewhat crude in how we take forecasts and allocate them to various geographic areas on the grid. And if we had better tools and were more thoughtful about understanding how population moves around, how new homes and new communities are created, that we might be able to do a better job in developing the transmission grid expanding; but also working with cities and counties to have them do a better job of planning the infrastructure necessary to serve their own growth. That is probably an issue that is more appropriate for the next cycle than this year, but one --

PRESIDING MEMBER GEESMAN: Let me ask you on that point, Pat, --

MS. ARONS: Yeah.

PRESIDING MEMBER GEESMAN: -- because I think that's an extremely important point and it's one that frankly Commissioner Boyd and I had hoped to make better progress on in this cycle than we did.

The ISO had asked that our demand forecast methodology be capable of a more granular disaggregation. They would like it down to the buss. I don't think our staff adequately responded to their request. And it's been identified as one of the top priorities for our new Executive Director in going forward with work plans, preparing the demand forecast for the 2006 cycle.

And we've asked, or I have asked that our management arrive at a written understanding with the Cal-ISO management that will provide a disaggregation in the next cycle that will be useful from the ISO standpoint.

I would be interested in any materials or suggestions that you might be able to provide to us in the next month or two along those lines that would assist our staff in planning what that work should look like over the next two-year cycle.

MS. ARONS: I would like to do so, and thank you for the invitation. Forecasting today, I believe, is largely driven by econometric models, what people believe is going to happen in the state. But those models don't get into the question of how does population move around.

And we started doing some research actually with Claremont College, that has a math department with a bunch of low-cost labor PhD students, who are able to go out and do some research.

And one of the things that we've learned through that process is that there are a lot of models out there that talk about how population develops in available lands, so that you have areas that are not developable because they already have particular land uses to day, whether it's parks or current development.

But they look at many interesting things related to traffic, infrastructure expansion, population growth, economy relative housing rents and things. It's a very interesting area of exploration, and one that I think the Commission should probably begin to look at for improving load forecasting.

PRESIDING MEMBER GEESMAN: Well, I actually had a discussion with our Executive Director yesterday on this very subject. And we have a tendency, which I regard as disabling many times, to always want to look at everything from a statewide perspective.

He suggested to me yesterday that perhaps in this particular area it might be most useful to proceed with a focus on one particular utility service territory.

So if that becomes something of interest to you I would certainly welcome the opportunity to work together in the next cycle.

MS. ARONS: Thank you. That concludes my remarks. SCE appreciates this opportunity to comment on the report, and is hopeful that the proposed processes move forward in a timely and productive manner.

PRESIDING MEMBER GEESMAN: Thank you for your statement. As I think you're well aware, your comments last year were instrumental in guiding our thinking on the corridor planning subject. And I think we still have some refinements to make there in terms of SB-1059. And I'm hopeful that as the Legislature goes to interim session we're able to smooth out some of the rough edges on that bill to both your company's satisfaction and the satisfaction of local government.

I also take to heart your comments about CEQA, which, I think, looms very large in everything that we do. On the generation side we've had our process certified by The Resources Agency as a CEQA-equivalent process. It's considered less cumbersome to applicants than the formal EIR process is, and that may be an area worthy of exploration in the corridor planning subject.

I also take to heart your comment about avoiding duplicative processes. And I think in the wake of FERC's decision on the Edison Company's trunkline proposal, it's something that the state agencies are going to need to figure out a better way to approach things, particularly in integrating the ISO's planning efforts into what state government ultimately relies upon for need determinations and other transmission planning characteristics.

So, as always, appreciate the comments you've made and look forward to working with your company in the future.

MS. ARONS: Thank you very much.

MS. GRAU: Okay, next on the agenda we're going to go back to item IV.B. on the agenda, which is back to Eric Toolson on assessment of low-probability/high-impact events.

MR. TOOLSON: The second presentation I'm going to make today will be on assessing low-probability/high-impact events. I'm sure those of you that are involved in transmission planning have recognized the value of a transmission line is dependent on recognizing these events and being able to incorporate the benefits from them. So that's what I'm going to talk on for a few minutes this afternoon.

First of all, I want to review quickly what I thought the benefits were. Why do we have these sensitivity cases. And I'll use the term sensitivity cases, extreme events, low-probability/high impact events synonymously. So, don't worry about reading a difference into that.

So why do we have these things? There's a lot of reasons. From my perspective the two most important ones are expected value and distribution of benefits. There have been other reasons that have been mentioned. Some is to define the range of benefits. Others are to help to understand insurance value for a transmission line, the strategic insurance value. And I think it has a role in that. But as I'll explain later, there's some parts missing in fully understanding the insurance value from this approach.

And so again I suggest the two primary purposes are expected value and distribution of benefits. I'll look at a recent case study so that we can better understand how these sensitivity cases were selected. For the Palo Verde-Devers study done by the California ISO that I was involved with as a consultant; and then the last one, some general methodology for ways that we can include it. Along the same lines as this morning, methodology that can be adapted to different situations in different resource and time capabilities.

Okay, purpose of sensitivity cases. Why do we have them here? Well, a lot of times we'll start out by looking at average conditions. And average conditions give us a base or reference case and tell us what the benefits are.

Now, if everything changed in a linear fashion we wouldn't have to do anything else. If you had a normal distribution of benefits once you define the basecase the expected value would be close to the basecase, or the average conditions.

That's not what we find in transmission. We find that the benefit distribution is often skewed to the right to include those high-impact cases. And therefore, unless you do multiple sensitivity studies you might be either overstating or understating these benefits.

Now this happened to be from the Palo Verde-Devers study. This is an extreme example of this. This is 2013 and it's from a participant perspective. From the Cal-ISO definition, participant means everybody participating in the market, transmission owners, generators, consumers.

You can see the reference case which is based on average conditions, average load forecast, hydro, market power and gas price. We end up with a benefit of about 6.2 million in this year, 2013. However, if we do the expected value we end up with something almost twice as high as that.

As I mentioned before, that isn't always the case. Often we'll see those two values pretty close together. We've actually seen them reversed.

The point here is the benefits are not

linear. If you increase your gas prices 20 percent you may not get the same impact you'd get if you decreased them 20 percent. And that 's why it's important to include these sensitivity cases for the expected value.

Now, the second reason we wanted to do this is distribution of benefits. This falls in with the risk topic I mentioned this morning. In this particular case -- represented by the blue vertical bars there. And then we've also plotted the expected value of that.

Now, let's assume in this case that the annual cost of the transmission line was $50 million right here. Well, this is the information we could tell from that. We could tell that 30 percent of the time the benefits are expected to be less than the annual cost. We can also see that 70 percent of the time the benefits would be higher. We can also see that approximately 5 percent of the time the benefits are expected to be greater than 150 million.

When we look at benefits down here, these are extreme cases. These might be built from say high gas price, high load growth, dry hydro, and high or moderate market power. And so when we look down here we can this provides an insurance value. It doesn't set the insurance value, but we can see that if those four conditions happen, and maybe system costs increase $2 billion in that year, that the benefits from this line would increase enough to help mitigate that or provide a shock absorber.

So that's the insurance concept we're talking about; it's not the insurance value, because I haven't done an exhaustive study out here. I haven't looked at all the possible cases. Insurance value's defined in two parts, right. Expected value and then the risk premium.

Say I wanted to go get life insurance. Say Gary DeShazo decided to offer life insurance to me, you know, as a part-time job after work. And, you know, Gary's generally a pretty comprehensive guy, but he has limited data. And he says, well, I only know the statistics if you get bone cancer, and I can tell you what that is. And I also see you're a little bit chubby, so there's a factor there involved. Okay, but those are the only two I can bring in.

Well, obviously if he's going to hire an actuary and come up with an expected value he needs to understand all the cases. That's one limitation of trying to get the insurance value here.

We're only selecting a small portion of that. And I'll talk about why we're doing that later, it's a tradeoff between resources available to do the study and the time requirements for it.

On the other hand we're seeing the insurance value demonstrated. The other part that's missing besides a more complete enumeration of the extreme cases, is the risk premium. After Gary's done all his actuarial studies he's got an expected value. And then if he shops that to me, and I pay a risk premium because I don't want just expected value, I'm risk averse and I'm willing to pay a premium on top of that.

We are also not addressing that in this study, either, so I just wanted to clarify. We look at some of the insurance concept; I wouldn't pretend that that is an actual insurance value.

Anyway, histograms are important. If I have another resource alternative and I see a big tail down here, that's going to be important to me. That means that there's some chances I can have some pretty significant losses. Where in this case the distribution on the loss side is fairly well contained.

On the other hand, I might have a fatter tail down there, or I might have an abrupt dropoff there. So I can have the same expected value, but entirely different histograms, which would be important to me from a perspective in considering downside risk and upside benefit potential.

Okay, let's go on to our case example. So those are my two reasons for doing sensitivity studies. To get a better value on expected value, a more accurate estimate of expected value; and to understand the histogram.

On the PV-2 sensitivity case, and I'll review this kind of quickly, they had four steps. And these are four steps that we're going to recognize and suggest in the general methodology.

First, they understand the variables, okay. They determine those variables. They select the ones that they're going to look at. In this study it happened to be gas, load, hydro and market power. Now, the ones they selected, they have to have a big impact on the results. They've got to be highly uncertain. And also you've got to be able to quantify the event and decide a probability.

As I mentioned this morning that's the problem with the market paradigm. That might be the biggest variable of all. It's hard to assign a probability to it, and it's even harder to model it.

Second, they decide the sensitivity cases that they're going to run. Third, they put probabilities to it. So I'll go through this pretty quickly.

Four variables, if you assigned only three cases to it, you could say five: very high, high, expected, low, very low. Okay. But four variable to the five conditions, okay. That's about 625 cases. As I mentioned this morning, that's not possible for us to do in a detailed transmission network. That's possible to do in a stochastic environment where you're doing a zonal type representation in a transport model. But there's drawbacks with that.

In this case when you're only looking at three, very high, very low and base, four variables, there's still 81 cases. That's more than any transmission study I know has done. Okay, so they used something that they called important sampling to knock that down to 25 cases.

And here's the principle. Even though there's a fairly complex mathematical approach to it, the principle is fairly simple. You pick cases in three categories. You look at the expected case, which is the basecase here. You look at extreme cases which are these four or a subset of those. And then you look at what's called the useful analytical cases, which are just the one of cases. You look at high hydro, everything else base. You look at low gas prices, everything else base.

So in the California ISO study they were able to knock down the 81 permutations to 25 cases. Now, at that point you still have to assign a probability to them, and you can't use the probability that you had initially because those 25 cases no longer sum up to one. And so they use the second mathematical technique, a linear program which is called the maximum log likelihood. And without getting into a lot of detail it insures the probability of those 25 cases is equal to one, and that each of the individual probabilities line up as they're supposed to.

Okay, then we go into proposed general methodology. This is what I think that somebody doing a transmission study would want to do. Now, again, this all depends on the case, you know, how complicated it is, is it a small series capacitor upgrade, a bit interstate transmission line.

First establish the stakeholder process. The stakeholder process is critical to hear the input of all the various participants, whether they're for or against the line. Recognize their concern and be able to provide meaningful data to them so that they can make a recommendation.

Second, and this is a little different than you'd think, I'd develop a basecase. The reason I develop a basecase is I don't know yet what variables have a big impact or not. I have a pretty good idea, and most people that have done these studies have a pretty good idea, but I don't know for sure. And if I've got a basecase then I can shock the basecase with different variables. I don't have to think what's the 90th percentile for hydro, I'll just take a real high year and run it through and see if it makes a big difference. I'll just take gas prices that instead of being $6 in 2005, may be $4 or something. See if it makes a big difference.

I'm developing the reference case for two reasons. One, it helps me understand how long it takes to iterate through a study. It gives me an idea of how many cases I can do. And then second, it tells me the variables that are sensitive, and which ones I want to include.

So, from that I select the uncertain variables. I develop the variable distribution. Now, there's been a lot of literature on that, and so I won't go into it. Some of it's historical; if you look at hydro, it's generally historical. Some of it's forecast error, there's other ways to do it. You get a variable distribution.

And you notice in here I'm not talking about correlations. The state of the art right now for long-term transmission study is to treat these variables independently. That's a good area for research. But I haven't seen a study yet that started to incorporate correlations, particularly since it's pretty hard to derive for the variables you're looking at.

Okay, so you get the variable distribution. That just means volatility. Might be a normal distribution, it might be a skewed distribution. From that you select your sensitivity cases. So you got to skinny down. Whatever number of variables you have you're going to have too many cases. This is where the important sampling came in in the Cal-ISO case.

I agree with the concept of important sampling. It's not critical to me that you go through the mathematical exercise, but it's important to use your judgment and pick the cases out that are most meaningful and the number that you can realistically model.

At that point, since you've eliminated some of the permutations, you need to reassign the joint probability. And there's probably different ways to do that. The way the ISO did it looked reasonable and legitimate to me. Then you go ahead and you do your simulations.

Just an idea of some of the current limitations from my perspective. There's not a lot of good data to do this. And so, for instance, I'll give you an example of hydro. You know, everybody thinks we have a lot of hydro data. We do. You go to BPA, you can look at their white book and get hydro data for 80 years. That's great.

Then how do I couple that with California? You get to California, I've got a high, medium and low. Should I put low with their low? Well, that's a different probability. How about northwest, southwest. And then particularly, Canada. It's hard to get hydro data out of Canada.

So when you're done you're trying to represent 100 years, 80 years of hydro data with just fragments that you're putting together. It's kind of a hodge-podge of facts. And so you'll see the data is limiting. That doesn't mean you don't do the studies. You do the studies as best you can.

This is one of Frank Wallak's big points is the data is limiting in our ability to do accurate and statistically valid extreme events.

I talked about some of the difficulties in modeling. Market paradigm is one that keeps coming up to me. We modeled an LNP world in Palo Verde-Devers, we modeled an LNP world for Path 26. One of the criticisms that was suggested is the rest of WECC's never going to be LNP. You know, either that's wishful thinking or it's impractical or something. I need to see one that has at least a hybrid where everybody outside of California is on a contract path, and California's LNP or continuation of a contract path model.

We don't know how to do that hybrid model very well. And we kind of struggled with it and came up with some estimates of it that we put in the report. But that's difficult to model.

Third, modeling inabilities to reflect important uncertainties. I talked about this a little bit this morning. We don't model transmission outages. We don't model either scheduled outages or forced outages. If we want to look at something that's really important like in the Palo Verde-Devers, we discretely took it out for a year. We looked at a derating of COI and East of River, for instance. We took the Pacific DC line out.

But to be able to incorporate that like you do a generator outage, that's not where the modeling capability is now. And it just needs to be recognized.

And probably the last one is the biggest bone to pick. Statistics requires lots of cases, the more cases the better. Extreme cases, being able to understand them, you get a better understanding of the distribution.

Transmission studies that do a detailed network model, though, are difficult to do. You have to develop the data. You run it. Invariably there's issues. You iterate, you review it. It's tough to get a case out, and you know, after say a week or something like that.

The Cal-ISO is limited to 17 market-based cases for two years. There are people who suggest why don't you do 2008 through 2018. You could, but you'd be limited to about two cases a year. And the value during those interim years, in my opinion, isn't as great as looking at different variables and extreme cases.

So that fourth point, you know, is a big driver. In the end you're going to be able to do a few sensitivity cases. You need to select them well so that you can get as much information as you can.

Okay. Having said all that, I wanted to end on more of a positive note. I think this stuff's invaluable. I think sensitivity cases are critical. Why? You can get a big difference in your expected value. You get a lot better answer, a lot better estimate for expected value even doing just a few sensitivity cases than only doing one basecase.

Second, you can start to define a benefit distribution. Without doing some sensitivity cases you have no idea what your benefit distribution is. You don't understand the downside risk or the upside potential. To me, that's an invaluable tool with respect to comparing alternatives.

Third, you can understand the impact of a lot of variables. We can understand the impact of high hydro, low hydro, gas prices, load growth. We may not understand them as well as we want. Reminds me of the lady that just spoke before me on load growth.

On load growth we looked at load growth at a macro level. We look at what it does at the utility or the state level. And then to get our nodal levels we take a single set of distribution factors and apply it to the utility load. Okay. That means all the load growth happens at the existing nodes in the same proportion it happened during a single hour. Now, if it was summer peak hour or winter offpeak hour.

So there's a lot of enhancements that

can be made, but there's still a lot of information. I can understand the impact of high load growth, okay. And then I can start to explore some of these more difficult things. I can make estimates on what's going to happen to capacity values, what's going to happen to different market paradigms.

And so from that I guess my message is yeah, there's a rigid or a robust statistical way to do this, and that's great if you have the resources. I don't see where the capability now permits you to do the number studies that you'd like to do in extreme cases. And so you select carefully and pull out what conclusions you can, realizing the limitations that may be there and the value of it.

Any questions?

PRESIDING MEMBER GEESMAN: Yeah, Eric. I've got some real concerns with what you've said. And I don't dispute the accuracy of it. But, let me try to provide a lawyer's perspective.

MR. TOOLSON: Okay.

PRESIDING MEMBER GEESMAN: And let's assume that I am a lawyer for a group of people or interests opposed to the transmission project that the Cal-ISO has just determined is needed.

MR. TOOLSON: Um-hum.

PRESIDING MEMBER GEESMAN: Haven't you just provided me with about 15 arguments as to why you, the Cal-ISO, did not do an optimal level of assessment and evaluation. And if I have the resources, can't I always come up with 15 reasons why your methodology could have been better, or you could have done more studies, --

MR. TOOLSON: Um-hum.

PRESIDING MEMBER GEESMAN: -- or your statistics would be more robust with more sensitivity cases?

MR. TOOLSON: Yes. But I think that's true on any study. Any study there's ways to improve that study. So, I have two comments on that.

First, I shouldn't indicate that I'm a representative of the ISO, I'm not. I just worked on those studies. But, Gary's here and he may want to comment.

PRESIDING MEMBER GEESMAN: Well, Gary's going to get the same questions when he gets up.

MR. TOOLSON: The other thing is, you know, I've been doing studies in one form or another for 30 years, as many as you have. There's always limitations. You always say this is the requirements, the resources I have available. How do I do the best study I can with those resources.

And that's the issue. Did the ISO take those resources and do the best study that they could.

Now, there'll be different perspectives. You know, people will say I think you should have looked at these cases, or these cases. But remember the state of the art here. Two years ago you would be lucky to do a chronological transmission model 8760, a basecase.

Last year if you look at some of the studies, for instance, that Tabers did, and I'm not critiquing those at all, I think they did a great job. GEmaps, they'd come up with a couple scenarios. So they're trying to decide huge seams issues with a couple of scenarios. That was great. We didn't even have that a few years prior to that.

Here they're taking it and they're saying, okay, instead of a couple I'm able to do 17 for two different years. To me the evolution on this is rapid, and the ability to have improvements is great. There are limitations, but within those limitations is the information that's being provided does that expected value have meaning or not; does that histogram have meaning or not. And I would argue that they are.

They're not as good as -- same accuracy as I would do if I had 100 cases, but I've done enough cases and I think I've assigned the probability correctly, so that the information coming out from that are very good indicators.

PRESIDING MEMBER GEESMAN: Well, I don't disagree with any of that. But, I think you've just given me several more arguments as to why we ought to defer a decision on this project and its alternatives for another year or two, because we'll have even greater analytic capabilities then.

MR. TOOLSON: I can understand that point. My response to that is, you know, that's true with any study. You'll have more information in a year and better analytical capabilities. Do we think that waiting a year for study improvements is going to help us make a better decision. Or do we think that opportunities will be foreclosed because we've waited a year on permitting and instigating the infrastructure.

I would agree with people that the information we have now is good, make a decision. I agree that people can come to different decisions with that data, but I think the information is valid enough to make a decision.

And given the concern with the timeliness and moving ahead and the consequences if you wait, I think it would be imprudent to wait.

PRESIDING MEMBER GEESMAN: Well, I agree with that, too. I guess the concern that I have is that I'm not in any way persuaded that these decisions are better if they're revisited again and again and again and again. And I think the challenge in front of us and the state agencies, the Cal-ISO is figuring out a way in which to do the best possible analysis that we can once. And make the results of that decision as legally defensible as possible.

MR. TOOLSON: I agree with that. Part of my reason in putting these up is, you know, to give you an idea of what the state of the art is, both pros and cons. And also to potentially allude to some areas that might be worthwhile focusing some of your research efforts in.

PRESIDING MEMBER GEESMAN: I appreciate that very much.

MR. TOOLSON: Any other questions? Okay, thank you.

MS. GRAU: Okay, now we are backtracking and doing the lead-in to part two which is on the transmission staff report, the green-covered report in the back of the room. And before I get into the content of that report, I just would like to acknowledge and thank all of my co-authors first. And they are Jim Bartridge, Mark Hesters, Lynn Alexander, Matt Trask, Clare Laufenberg Gallardo, Merwyn Brown, Don Kondoleon and Bob Strand.

In addition, we had help with the detailed transmission project writeups in chapter 3 and appendix F from the following transmission unit staff, Sudath Arachchige, Ajoy Guha, Jim McCluskey and the recently retired Al McCuen.

I would also like to thank Marylin Davin, Peggy Falgoust, and Carolyn Walker for their excellent editorial support. As well as Terry Rose and Andy Churchill for their help with our transmission map.

Okay, so in terms of topics covered you can just read these bullets. The summary of policy options, I just want to note that those are attached as a handout to the PowerPoint presentation. They're pulled from chapter 6 of the staff report.

Okay, so I'm just going to walk through briefly the report; hopefully you all had a chance to sit down with it at lunch and read it from cover to cover. So I'll make this brief.

The chapter 1 introduction, we just set the stage for this year's work based on the previous work we did in 2003 and the 2004 update years. We note some of the progress that's been made in implementing the recommendations that have come out of the two previous years, including things like the creation of the Imperial Valley study group. And we note also that the Cal-ISO has modified its transmission economic methodology to incorporate some of the Energy Commission's recommendations on strategic benefits as Joe Eto spoke about this morning.

And the chapter 1 also notes other significant developments since the report was published in December of 2004. This includes things like the dedication of the Path 15 upgrade; the increased rating on Path 26 from 3700 megawatts to 4000 megawatts; and the new temporary Miguel-Mission number two project that was energized, that Jim Avery spoke about this morning.

Chapter 2 goes into some of the policy items. The need for collaborative long-term transmission planning has been a theme that has run through the staff and energy policy work since 2003. And we note in there that the ISO is developing a more proactive approach to transmission planning, and we're hoping that Gary DeShazo will be able to talk about that a little bit when we get to him.

We talk about the proposed criteria for evaluating transmission and alternative sources. Since then, today we've had the update on that from Eric Toolson. So our report is, in a sense, outdated. We are planning to publish an addendum to the staff report. I'll mention that later, but that will bring everything together that we've heard today and so we have a complete record.

The third bullet, improved assessment of transmission costs and benefits. That's also some of the work that Joe Eto and Randall Hunt talked about this morning. And under coordination among western states, we point out that the group called the Western Assessment Group, WAG, has been formed.

It's an ad hoc group that was formed just in January to identify the major commercial issues affecting the western interconnection. And their charter is to evaluate whether the west has the industry and regulatory institutions in place to effectively address and resolve these issues.

And they've categorized their work into four categories. And one of those is transmission planning.

Chapter 3 and appendix F is where you'll find the meat of the report, which is the description of transmission problems and the projects that can solve some of those problems.

So we begin by grouping the infrastructure issues into four areas. We've harped on these quite a bit. Local reliability, congestion and renewables; kind of a three-legged stool of SDG&E, and then plus we have a category called regional, which is out of state or interstate.

We also talk about the role of emerging transmission technologies, and the Public Interest Energy Research that is underway is described in appendix D of the report. So there's more information there.

And then finally we did an assessment of 21 major transmission projects affecting California. And those include some understudy; some that are planned; some in permitting; and some under construction.

And at the end of this presentation, for those of you who hang on long enough, we'll talk about staff suggestions for -- strategic plan.

And this is just -- I don't expect you to be able to follow this, but if you want to see the detail, it's on page 36 of the report. This is just the map that shows 17 of the 21 projects that we could actually fit on the map.

Where they're all located, you see the majority are in southern California, and then the Bay Area, San Francisco Bay Area.

Chapter 4 is on transmission corridor planning and development. We have developed a proposed state-led transmission corridor planning process that has three parts to it. In part one we would identify corridor needs in the energy report process; establish corridor priorities; identify major permitting, environmental and land use issues associated with corridor. And identify the agencies whose participation is critical in resolving these issues. This process would also include stakeholder and public input.

Part two would include state designation of corridors to provide utilities with future permitting certainty and incentives to acquire land for future system expansion. This would be a separate process from the one noted in part one, and it could occur outside of the energy report timeframe.

The part two designation process would be a public process initiated by an applicant's filing, or the Energy Commission's own motion. And would include an assessment of environmental impacts of a proposed corridor in accordance with CEQA. For part two the state must establish designation authority.

The most efficient way to acquire land needed for future corridors is to rely on transmission-owning, load-serving entities to do it. In order to insure that land is available within the corridors identified and designated, the CPUC needs to extend the length of time an IOU is allowed to keep the cost of land acquired for future needs in its ratebase. The ratebase is currently limited to five years.

Chapter 5 we talk about impact of transmission on renewables development. We talk about operational challenges, such as accommodating intermittent generation from wind and solar, to a lesser extent solar. And we also talk about minimum load issues, scheduling and dispatch challenges.

And then the system constraints, the lack of transmission within resource areas; and then transmitting remote renewable generation to load centers in an already congested system.

So we're not implying that the renewables are causing the problem. There already is an existing problem. It just gets exacerbated by the addition of renewables.

Chapter 6, I'm not going to go through the exhaustive list of options, policy options, but they are attached in your handout. And they come directly from chapter 6. So I'm going to skip over that in the interests of time.

Okay, we would like to get some feedback from the parties today, if possible, on the guidance questions which we posted on our website. These are did the staff accurately capture the parties' input to date. Are there other relevant points. Did staff draw appropriate conclusions. And did staff identify appropriate policy options.

And so what input we get today, and also we have a comment deadline of next Thursday, August 4th. So we will consider all that input and everything we've heard today, the complete record from our consultants and such, and publish an addendum sometime in August 2005 to complete the record.

And so we are charged with developing a strategic plan. PRC section 25324 was added late last year, not in time for the 2004 energy report cycle. But it requires the Energy Commission to adopt a strategic plan for the state's transmission grid. And it specifically says this plan shall identify and recommend actions required to implement investments needed to 1) insure reliability, 2) relieve congestion, and 3) meet future load growth in load and generation including, but not limited to renewable resources, energy efficiency and other demand reduction.

And so the second part of the guidance questions we posed on our website are the following: Do the projects presented in chapter 3 and appendix F of the staff report provide an appropriate foundation from which to develop a strategic plan. Which of the projects in chapter 3 and appendix F should be considered for inclusion in the strategic plan and why. And are there other projects that should be considered.

And so staff's initial thoughts on winnowing the list of projects we have in chapter 3 and appendix F, these were kind of the criteria we came up with. We want to focus on the near term, those projects that have an online date by 2010. We want to focus on the ones in need of siting approval so we're not counting the ones that have already received, for example, a CPCN from the PC.

And obviously they need to meet the guidelines that I've just outlined from the legislation, insuring reliability, relieving congestion, meeting load growth and supporting renewables development.

And then finally being consistent with the recommendations we've made in the past two cycles, especially with respect to the strategic benefits, such as those that Joe Eto mentioned this morning in his presentation. Things like decreased market power, environmental benefits, and insurance against contingencies which we've also heard quite a bit about.

And so we consider the following projects of the 21. These are numbered, by the way, consistent with appendix F, so the project number you see after each project is our numbering of the project from our chapter.

So, in the San Diego/Imperial Valley area we believe the ones that should be considered include the San Diego 500 kV project, which we heard about this morning. Also the Lake Elsinore advanced pump storage or LEAPS project. And then the Imperial Valley transmission upgrades which complement the San Diego project.

And then for the southern California Tehachapi region some congestion management south of Lugo project; Path 26 upgrades; the Palo Verde-Devers 2 project, which is currently at the PC for CPCN; and also the Tehachapi segment 1 and

Tehachapi segment 2, which are also at the PC for CPCN approval.

And in northern California the TransBay DC cable project. And the Metcalf, Moss Landing 230 kV reinforcement.

And so to conclude, the Committee draft of the strategic plan and the Energy Report, they're on the same cycle, so Committee drafts of both of those documents should be available by September 8th up on our website.

We have hearings around the state scheduled for late September. I believe those dates are now set completely. Bakersfield, San Diego I think, and Sacramento. Is that right? Yeah.

Committee final versions of the strategic plan and Energy Report are scheduled for mid October; and then Commission adoption in early November.

And so if there are no further questions we're going to continue on the agenda with Los Angeles Department of Water and Power. Randy Howard.

MR. HOWARD: Thank you for putting on such a good workshop on such an important issue.

My name is Randy Howard; I'm an Executive Assistant to the Chief Operating Officer of our power system at Los Angeles Department of Water and Power.

And before I get started I want to make a few observations. A commitment that we had made to the CEC this last year from the Department was greater involvement in and participation in the IEPR process and some of your workshops. And to that end I want to introduce John Kerrigan. John, back here. John is a DWP employee that is relocating to Sacramento for the purposes of working closer with the CEC, as well as with the legislative body.

Let me jump into a few things and comment on some things that we heard today. Before I do that, though, last Thursday we hit an all-time record in Los Angeles of peak demand. And on Friday we did exceed that.

Our peak demand on Friday was 5708 megawatts. And we hit that despite the loss of our single largest units out of the Intermountain Power project. We lost those units, we believe, to a lightning strike that occurred someplace in Utah. And we were able to keep the system up and running.

We did have to curtail sales we were making or had proposed to make to Southern California Edison at the time. We were making sales of about 550 megawatts in addition to serving our load. And the system did stay up. We were able to get some additional capacity from some of our friends in Nevada, as well as in the Phoenix area to keep the system up and running.

They were not able to see where lightning hit the line, but we were pleased to see that things worked as they should have worked in that kind of emergency with those kind of temperatures and loads on the system.

PRESIDING MEMBER GEESMAN: Randy, how's the 5708 compared to last year?

MR. HOWARD: This exceeds our peak. The last peak of this size was a peak that occurred in 1998. Last year was relatively cool for our system. I think we were about 5400 last year.

PRESIDING MEMBER GEESMAN: And do you ordinarily peak in July, or are you a later peaking system?

MR. HOWARD: We normally peak the end of August, the first week of September. So we still believe we have a long summer ahead, and plan on watching our system very closely.

This was also at the time where Mojave was having some problems and we had some units off at Mojave. We weren't taking a lot of capacity, but we did have some problems with Mojave.

PRESIDING MEMBER GEESMAN: I recognize that, you know, you have to weather-normalize forecasts and peak adjustments, but my arithmetic suggests that this year is running about 5 percent or more above last year in terms of peak demand.

My guess is that our last forecast for you guys on a ten-year basis was probably of annual growth less than 2 percent per year. Sound right?

MR. HOWARD: That is correct; it's less than 2 percent. Our one-in-ten peak event is about a 5800.

PRESIDING MEMBER GEESMAN: Um-hum. So you're not quite there yet, but you're headed in that direction.

MR. HOWARD: We'd rather not head in that direction this year.

All right, just a few observations. We will make more formal comments as to the reports, and we will file those comments.

Each year the Department of Water and Power develops a ten-year transmission plan and assessment. We did provide that this year to the staff, and that was used, I recognized some of the work in the report that was developed by staff. We're preparing the 2005; it will probably be issued sometime in September. It will also take a look at new transmission projects that have recently been considered by the Department.

Most of the projects in the report focus on our load growth and reliability upgrades, primarily in the service territory. But we are looking to bring in additional renewable energy. And looking at several upgrades as to our transmission system to accommodate that.

We are currently participating in the development of the Public Power Initiative of the West. We were involved in their recent release of a paper, policies for a successful implementation of transmission plans within the western interconnection.

That paper endorses contract-based agreements, fixed terms and conditions, and no market-determined charges, either for congestion or for losses.

With that I'll also make a comment as to what was stated by Navigant on congestion charges. Just to clarify some of those statements in that presentation. The activity at Sylmar we do not view, at least from LADWP's perspective, a congestion issue and interconnection issue with Southern California Edison.

We did install last year a transformer at LADWP's expense that did increase the capacity to about 1600 megawatts that can transfer back and forth. There are some limitations, it's our understanding, on the down side that isn't system related to the Sylmar facility.

The congestion that was identified appears to be related to a scheduled and planned upgrade of the Celilo-Sylmar DC transmission line. I think if you were to look at the net benefits of that upgrade you'll find that the cost benefits were significant for all participants and those in the state.

And really, looking at just the congestion that might have occurred while that outage was occurring and that upgrade was occurring is probably not something that should be used in other forums.

Also on other interconnection points with Southern California Edison there was an interconnect. It was identified, it was an emergency interconnect. It is not used. We attempted to use that interconnect right after the '94 earthquake. It was like opening a dam and our voltage was collapsing as we were trying to feed into the Edison system to help them restore power.

We had to open that back up. It's not very strong. It probably is one that we'll have to look at longer term. At this point we don't view that as a reasonable interchange point.

So those are just a few comments that I wanted to make there.

Also, LADWP is a founding participant of WestTrans. I know there's been discussion previously of WestTrans and having a common oasis. Currently we are working towards more common business practices with WestTrans. We have -- or we've seen a significant number of benefits, and that's really gaining a greater efficiency out of your existing transmission. And that should be all our goal instead of just looking at planning and preparing for new transmission. But how do we best utilize existing transmission that is available. And we believe WestTrans has done that.

In the reporting period, 10.5 months on WestTrans, we had about 527 transactions. Whereas for the previous 50 months on our transmission system we've had about 171 transactions. So, a phenomenal growth on the use of excess transmission, posting it on the common oasis for all to see what's available. And to be able to easily conduct business with other entities.

So that is something that we continue to look at, similar to DWP looking at repowerings, as a means to look at our long-term generation requirements. We have been looking more at how do we better utilize the transmission.

A comment was made before we do build new transmission we want to make sure we optimize what we currently have and upgrade what we can to meet future growth.

PRESIDING MEMBER GEESMAN: Who are the eligible participants in WestTrans?

MR. HOWARD: I don't have an entire list today, but it includes most of the utilities in the western states. Unfortunately Cal-ISO is still not a participant in that activity.

I'll also make note that in the Navigant report it discusses some congestion charges that we might have -- that LADWP might have made sales to Cal-ISO. We did not make sales to Cal-ISO. Our credit risk policy within the City does not allow us to make sales directly to the Cal-ISO.

We've had several meetings with the management of the Cal-ISO trying to resolve those issues. Currently we just have bilateral contracts directly with the other parties such as Southern California Edison or San Diego Gas and Electric.

That's unfortunate. We still hope to work to resolve that. And the new CEO at Cal-ISO seems to be committed to getting that resolved over the long term.

A couple other observations just as to renewable and transmission plans for such as the Tehachapi area, as well as the planning that's going on down in the Imperial Irrigation District area, the Salton Sea. We remain involved in both of those planning groups for transmission.

We are currently looking at our Owens Gorge 230 kV line; runs very near Tehachapi area.

We believe it's going to serve quite a lot of our renewable requirements going forward. It's a 450 megawatt line. We currently dedicate about 170 megawatts currently for hydroelectric out of the Owens Valley. We've reserved about 120 megawatts from our Pine Tree project. And we have 160 megawatts remaining, and which we are looking at renewable projects to tie into that line.

We have some options there to maximize utilization. It can be upgraded to a 500 kV. We are looking at that, working through some studies now, and other alternatives to get some of the renewables out of the Tehachapi area.

PRESIDING MEMBER GEESMAN: Now is that current capacity available through the WestTrans system?

MR. HOWARD: Yes, it is.

PRESIDING MEMBER GEESMAN: But a party would have to meet your existing credit requirements, would they not?

MR. HOWARD: They would. And typically the WestTrans, we would be posting more short-term basis.

PRESIDING MEMBER GEESMAN: What duration of contract or obligation?

MR. HOWARD: On the WestTrans they're typically short term, you know, you would talk less than 30-day type transactions.

PRESIDING MEMBER GEESMAN: Okay.

MR. HOWARD: If we were discussing anything longer we'd be looking at bilateral contract negotiations.

PRESIDING MEMBER GEESMAN: Okay. And that would be directly with the City?

MR. HOWARD: With the City of --

PRESIDING MEMBER GEESMAN: Or the Department of Water and Power?

MR. HOWARD: -- Los Angeles, correct.

And as you know, part of the project for the Pine Tree is to build an 11-mile spur into the, north of Mojave into the Tehachapis.

We do have a long history of coordinated transmission planning where the needs of a number of utilities are met simultaneously. Coordinated planning efforts have resulted in the Pacific DC intertie. Transmission has been built in conjunction with the Intermountain Power Project.

We are currently looking at upgrading that line. That line was originally designed for the four units that were proposed at

Intermountain. There's only two currently. A third one is in the development stage. L.A.'s not involved.

But the transmission needs additional capacity could come down from there. And so there is some discussion of looking further at that. Might assist in the frontier line development. It would be a transmission corridor that would fit that need.

We also recently were involved with other participants in the Mead-Adelanto and the Mead-to-Phoenix projects. And as you know, there is current activity on the Palo Verde-Devers line; still quite a lot of discussion between Southern California Edison and LADWP as to our contract issue, but both parties seem committed to trying to resolve that. And we are hopeful that will be resolved shortly.

PRESIDING MEMBER GEESMAN: Can you venture a guess as to which quarter shortly falls in?

MR. HOWARD: I would hope before year end we could have a resolution that would satisfy most parties. Again, from LA's perspective, ours is to insure that our ratepayers would have cost certainty as well as deliverability going forward. That really is an issue that we have to resolve also with a third party, not just Southern California Edison, but with the Cal-ISO on how that could be developed.

PRESIDING MEMBER GEESMAN: Um-hum.

MR. HOWARD: Future collaboration efforts continue to face some challenges, and those are really under-proposed FERC redesign markets, and some of the issues that we are having with the Palo Verde-Devers.

And we see that in some other projects that we are looking at, such as the Salton Sea area, bringing some geothermal out where we could jointly do that with some other participants. Yet a lot of questions as to control area operators and some of the pricing.

So, in closing, LADWP is committed to new transmission. We are committed to your process here. We think it is a very significant movement as to getting additional transmission built.

We think there is quite a lot of value for the ratepayers in California to have additional transmission. Our transmission costs are some of the highest in the state, I think, as a utility. But I think our generation costs are some of the lower or lowest cost, other than some of those entities that have significant amounts of hydroelectric.

PRESIDING MEMBER GEESMAN: And some of us would argue that the high transmission costs you've been willing to incur are directly correlated to the low generation costs you've been able to enjoy. I wish others around the state recognized that correlation.

MR. HOWARD: I think we would fully agree with you there.

Some of our issues still remain with market design, both FERC issues, as well as Cal-ISO issues, as to our commitment and ability to participate in projects. And we're hopeful that we can resolve some of those.

We believe that a few of the recent changes, or some of the things that are in the current Energy Bill that was just passed by Congress today, and will go up before the Senate tomorrow, provides us some longer term protection as well as the drafting of the uniform refund authority. And our ability to sell it to the market appears to be protected as long as we're in bilateral contracts. So we think that is significant.

Another observation as to the report and looking through it. I think we need to take a little bit more time in working with the federal agencies. San Diego presented that case very well. They're very much landlocked by federal land agencies.

Most of California, when you get to the eastern side, is landlocked by federal land agencies. I identified problems previously as to vegetation management, the ability to maintain existing rights-of-way for transmission on federal lands. We have a significant amount of problems.

We've had issues with fires in the state, and the ability to keep the brush away from our transmission corridors. There is a White House conference that will be looking at this issue coming up the end of August with all of the federal land agencies being represented.

The Federal Energy Bill does have provisions in it now for vegetation management. We were very pleased with the work of both the investor-owned utilities and the pubic power to get that in there, to try to put some priority as to permitting and maintenance of rights-of-way for transmission corridors. So we think that will strengthen some of our work going forward.

The federal land agencies have asked that we focus more time and attention, when we're talking on transmission, with partnerships. You know, how can we work better on partnerships with those agencies to accommodate our utility corridors as well as some of their needs. That might be better road maintenance; sharing of road maintenance. That might be sharing of some security measures as to protecting those lands.

And that's what they'd like to spend a little more time with us on in the future. That might be a segment of your evaluation into next year, possibly, with those federal agencies; that we can come together and find out how best to plan on transmission corridors and get those sited and approved.

PRESIDING MEMBER GEESMAN: Randy, thank you very much for both your participation in this cycle and your appearance here today.

As you're aware, we spent a lot of the last couple of cycles beating up on the City and asking why you guys don't do what we want you to more often. I would invite you, in your written comments, to give some thought to what you'd like state government to do in the transmission area that would better serve the City's interests. Because I think they're highly compatible with what the state would like to see.

MR. HUNT: Okay, we will do that. Thank you.

MS. GRAU: Okay, next on the agenda is Chifong Thomas from PG&E.

MS. THOMAS: Good afternoon. PG&E will have other comments, but this is just some initial thoughts that we have after seeing the report. And overall, it's a great effort. And the Commission Staff should be commended for that.

Okay, basically there are two major topics. One is some thoughts on the corridor identification designation and right-of-way acquisition and banking. And the other one would be comment on some of the identified projects that was in the chapter 3 and appendix 5.

And PG&E believe the collaboration between the state agencies, the ISO, and the transmission owners and the stakeholders would give you a more rational and efficient process in planning and implementing transmission plans.

And also in addition, PG&E welcomes the opportunity to review and comment on the CPUC mitigation compliance matrix prior to its finalization.

Here's some suggestions on collaboration. We need some collaboration on ways to expedite CEQA review process. And maybe some better coordination of activities in general through the process. There should be some adequate consideration by one agency of another agency on the expertise and regulations. That way we'll minimize duplication of work.

The notice to proceed issuance could be staged so it doesn't have to wait for everything to complete before the task would have be done. And then also the corridor designation process would have to somehow have some way of requiring future agencies to improve projects to be constructed within the CEC designated corridor. Unless there was some standards to reopen the previous environmental process. Because otherwise we'll be in this loop over and over again.

Here's some issues. Transmission

project further out in the future would probably benefit more from early identification of corridor. But then also, these projects also would have the greatest uncertainty.

There are legitimate changes in transmission and generation plans that could lead to changes in identified established corridors. And then one concern that PG&E has is the fact that once a corridor is identified it would impact land value and impact communities. And it could have potential taking issues. And so we need some clear support from the Legislature and the local agencies before we proceed.

When you come down to transmission projects, they have two broad categories. One is to accommodate new resources and reduce operating costs and provide operating flexibility. And those would be, of course, generation related.

And then the other category is to supply load, customer load reliability. There are uncertainty associated with both type of transmission projects, but there are more uncertainty associated with those who accommodate resources.

And one reason is because at least the

utility would be able to project, even however imperfectly, load growth by checking with our customer representative and our monitoring into 44 hour customer reps. But with resources, in this day and age there's no control over where, when and how much resources it would develop. And then also resource could develop a lot faster than transmission can be built.

So, I think that we need a big-picture approach. We should expand the study scope to include all credible coincidental new resources. So instead of studying one cluster at a time, we need to look at the whole state as to where the resources we'd like to develop. And a transmission plan can flow from that process.

And by devising transmission plan we are really talking about going into looking at power flow and stability programs, and those would be a program that we're looking at one moment in time. And it's very difficult to try to look at expanded amount of time.

So, to keep the process manageable, we need to take simple approach to start with. We can expand later. And we should identify a few corridor that would meet many of the potential needs, instead of numerous corridors going to every potential growth area.

And there also must be flexibility so the corridor identification can be adjusted later on as new information develops.

So, here's some suggested steps. The CEC can develop a number of resource scenarios for the entire state similar to the SVA effort that you have started. And then the ISO and the -- well, PG&E -- actually just not participating owners, but just transmission owners in general, can develop a transmission plan to accommodate resource scenarios through a stakeholder process.

And so the uncertainty can be reduced by selecting those transmission projects that are common to a number of credible scenarios. So, as we overlay one credible scenario on top of another one, then we develop plan for that. And sooner or later you see a pattern of transmission projects that could be common to a number of scenarios.

And then the transmission project that identify more scenarios could be given a high priority. The CEC can track the resource projection development and provide update to the resource scenario. And that can be incorporate into the next transmission corridor identification cycle.

The reason we're doing it all at once, I mean you're doing a scenario like this is that rather than doing cluster at a time, you do one cluster at a time, different clusters have impact on the other clusters. And so then it becomes very difficult to try to link the interrelationship of different scenarios.

Then for the corridor destination process, there's some thoughts that we have. The CEC proposed corridor destination process appears to require determination and need and the preparation of PEA, that's proponent's environmental assessment.

Because the costs associated with PEA is -- and the requirement of CEQA is pretty time consuming and, you know, timing and criteria for this preparation is really important. And it costs quite a bit of money. And, in the tens of millions when we're looking at the full-blown PEA and then a CPCN process.

And so our cost recovery is very important to PG&E, but the cost to our customers and the impact on the community must also be primary considerations.

Another thought is that transmission is under FERC jurisdiction, so we will also need to work with FERC, because FERC rules would say that the transmission owners cannot recover the cost of obtaining a permit until the associated project is operational. So it has to be used and useful.

So, suppose we obtain a permit today and the project may be delayed or may not be implemented until, say, 30 years later. And that delay in cost recovery gives incentive to designating and acquiring a banking right-of-way.

And also the state regulator support would be needed on this cost recovery, and the TO's rates in advance operation.

PRESIDING MEMBER GEESMAN: Now, let me ask you on that point, would that apply to right-of-way acquired in advance of knowing exactly what size or scale project ultimately might be built on that right-of-way?

MS. THOMAS: I'm not sure, because what happen is from the way that I understand is that when we plan a project we would have the corridor designated, and then we'd have the right-of-way, you know, to get a permit and the required. And when a project's become used and useful, then everything would roll into the ratebase, the transmission ratebase.

And so we would acquire right-of-way ahead of time without any project to attach it to, that may be a problem. And then, of course, even if you had a project attached to it, finally the project was built on the right-of-way and become used and useful, it could be many years from then.

PRESIDING MEMBER GEESMAN: You might ask your legal division to look at the staff recommendation in terms of expanding the amount of time that the CPUC will allow you to carry land in ratebase as to what would trigger FERC jurisdiction in that situation.

Because I read the staff recommendation as focused on a right-of-way acquisition quite a bit in advance of the actual FERC approval of wires and towers.

MS. THOMAS: Well, my understanding is that if we have right-of-way and it would be keep in the ratebase, that for five years and after five years you'll be a shareholder responsibility for the upkeep.

PRESIDING MEMBER GEESMAN: And I think

the staff is recommending that five-year period be expanded.

MS. THOMAS: Right, but then in order before we get a corridor we have to get the permit. And the permit will have to be, we will need a PEA or some sort --

PRESIDING MEMBER GEESMAN: Right.

MS. THOMAS: -- to say why we need a permit. And that costs a lot of money.

PRESIDING MEMBER GEESMAN: Yes, I understand that. But I think the staff has contemplated you getting a state permit of some sort. I don't believe the staff has thought of it as getting a FERC permit.

MS. THOMAS: Yeah, that's where the interesting part come in, because transmission is under FERC jurisdiction, so I'm not sure how we can roll that into a state rate.

PRESIDING MEMBER GEESMAN: Yeah. And that's why I'm suggesting that you have your legal division take a look at that. Because I don't know what the answer is, and I would certainly be interested in seeing what your lawyers think the answer is.

MS. THOMAS: Sure, and I don't want to

play lawyer right now, since I'm not one. Not qualified to be one.

PRESIDING MEMBER GEESMAN: Don't sell yourself short.

(Laughter.)

MS. THOMAS: The land acquisition banking, this flows directly from the discussion earlier, is that we believe that in some cases early designation of corridor can help expedite the transmission siting process. But only if we don't have to do it over again. In future agencies would have to be able to approve a project that was proposed to be built within the corridors.

But then the actual purchase of the designated right-of-way ahead of actual need is we think it's unnecessary and wouldn't expedite the siting process because once you get a permit, and it would only take months to acquire all the right-of-way.

And we've had experience that when we were building the -- way back when, when PG&E had built the Pacific intertie, and there was thought at the time to build a third intertie down the east side of the valley. And some right-of-way were acquired, and we wind up having to give it up piece by piece. And then finally when the COT project, which constitute a third intertie, came down, it is actually coming down on the west side of the valley.

So there's certain uncertainty that could be daunting when we try to acquire right-of-way too early.

PRESIDING MEMBER GEESMAN: Yeah, let me ask you there, we're getting different feedback from the different utilities on that question. And if you and your two colleagues could arrive at a common position, I think it would be highly informative for us and probably for the Legislature, as well.

I don't think anybody wants to encourage the expenditure of ratepayer funds for something that ultimately is not needed or ultimately is not useful. But we are getting a different perspective from each of the three companies. And I think we need to establish some common ground there.

MS. THOMAS: I think one of the reason is that, for example, the 500 kV intertie is really more of choice outside the populated areas.

And so, of course, -- and also a 500 kV line is a lot more uncertainty than lines to supply load within a more populated area.

The web-based corridor siting model program, why we think this program would be a useful tool, but you shouldn't replace the quality assessment of on-ground work. So for a transmission siting process to be effective and efficient, we need to take into concerns of all parties, that have to be identified and addressed.

And there are also practical limitations to incorporating all variables necessary for routing studies into a model. And so we just want to caution that incomplete data and issue identification could lead to unnecessary delays.

Again, this is a good tool. We just need to keep that as a tool. And it should not replace actually on-ground assessment.

So the summary on suggestion of process is that, well, let's take a big-picture approach. The CEC can develop the resource scenarios, and the ISO and the transmission owner can develop the potential transmission plans. And based on the resource scenario and the potential transmission plans, we can identify and prioritize the possible corridors through a stakeholder process.

And then the state and local agency can incorporate that into the corridors into a general plan. And then finally, can review the potential corridors -- I say annually, but I'm not sure that would be the timeframe. May cause some heart attacks here --

PRESIDING MEMBER GEESMAN: I was going to say, easy for you to say.

(Laughter.)

MS. THOMAS: So and then update as a new resource scenario develop.

PRESIDING MEMBER GEESMAN: Let me ask you to go back to that last slide. Stay focused there and give us your thoughts as to how we should address this takings issue which you have raised.

MS. THOMAS: I really don't have any idea how you could address it, because that's one of the sticking points that we have. Because if we go in and say, and identify a right-of-way around some community, and they have to hold that open for us. And then we really don't -- then our plans change. Say five or ten years from now we decide that we're not going to do it, we're not going run a line down there anymore.

Then, you know, how are we going to tell the community that, yeah, you did all these things, we just kidding, and thank you very much.

PRESIDING MEMBER GEESMAN: And is that problem mitigated if we don't require the general plans to be amended.

MS. THOMAS: But then if we don't do that how would we know we can build in there.

PRESIDING MEMBER GEESMAN: Well, --

MS. THOMAS: I mean that's a dilemma here.

PRESIDING MEMBER GEESMAN: We can't give you land use for nothing. Once you've established that you want to build there, you do have a taking, unless you provide compensation.

MS. THOMAS: That's correct, yes.

PRESIDING MEMBER GEESMAN: So we need to wrestle with this. And the Legislature is hoping that we successfully address it during the interim session. I certainly invite your company's best contribution in helping us resolve it.

MS. THOMAS: Well, we certainly would look forward to it.

Here's some specific comments:

Jefferson-Martin 230 kV line is making good progress. We expect it to be operational in the first half of 2006. And we plan to shut down Hunter's Point in 2006 following the energization of this project. So it's still on track.

Project number two and number three, these two could be the same project depending on the cost and the need. Or, you know, it could be different project, too, but it could be the same project. And the stakeholder and the ISO are still evaluating alternatives.

A project, something, is needed by 2012 at the earliest, and this project does not impact the plant shutdown at Hunter's Point Power Plant, which is on track for 2006.

The Greater Fresno project, which is Henrietta-Gregg reconductoring project, which has just received CPUC approval and PG&E plan to be in construction in 2006.

Project number 16, which is Tehachapi area renewable interconnection, we support the RPS target and schedule, and will work to make sure that the most cost-efficient solution would be there to support the statewide goal. The transmission need would be based on real IFO results, which are beyond the control of PG&E. So we may or may not consist of a direct interconnection from Tehachapi north to PG&E transmission network. We're still doing studies on that.

The identified problems is north of Midway and those need to be first resolved. Because as the study that I presented earlier in, I think, May 19th - anyway, it actually shows that Path 15 would reach a limit before Path 26 in a south/north direction.

Now, the Path 26 upgrade, up to 4000 megawatts, is actually from a north-to-south direction. And so we have in a south-to-north direction Path 15 actually reach limit first. So a direct line from Tehachapi to say, for example, Midway is not really needed until there is a need to schedule more than 1500 megawatts north to northern California, and Path 15 is fixed somehow.

So, is any questions?

PRESIDING MEMBER GEESMAN: I understand that the evaluation you've made on the Tehachapi interconnections. Do you think it's possible that from the ISO's perspective, looking at benefits both in northern and southern California, and looking at potential enhancements of Path 26, that they could come to a different conclusion?

MS. THOMAS: They may. That's the reason why we think we should be studying coincidental generation on the state. Because what happen is that if you're looking at Tehachapi alone, and that's the conclusion we'll come up with.

Okay, now we're looking at a north-to-south situation to supply southern California. There could be a different conclusion. And that's the reason, the danger of looking at only clusters, one cluster at a time.

PRESIDING MEMBER GEESMAN: I think that's a very good point, and I certainly thank you for your presentation, Chifong.

MS. THOMAS: Thank you.

MR. SMITH: Ms. Thomas, I have one quick question for you.

MS. THOMAS: And I thought I was going to escape.

MR. SMITH: This should be an easy one. Going back to your comment about Jefferson-Martin and the closure of Hunter's Point, I know the landscape on the Peninsula has changed. It's fairly dynamic, and -- over the last several years, but is Jefferson-Martin, the completion of Jefferson-Martin the only requirement for shutting down Hunter's Point? Or were there other upgrades or modifications necessary?

MS. THOMAS: Yes, there's another one, it's the Potrero-Hunter's Point, I believe. But that one is going to be on track also. They'll be completed about the same time.

MR. SMITH: Okay, I just wanted to clarify that.

MS. THOMAS: No, that's -- of course, Jefferson-Martin is not the only one.

MS. GRAU: Thank you. Before we move on to the next speaker, we have some people listening in on the phone, and we're getting some feedback in the form of heavy breathing.

(Laughter.)

MS. GRAU: So, if you could put your phone on mute, we'd really appreciate it. It would help out in here. Thank you.

And at the end, after our last scheduled speaker, Gary DeShazo, we will have an open discussion. We have one blue card so far from somebody who'd like to speak. And then if anybody on the phone would like to speak, you can then reactivate your line so we can hear you, okay. Thank you very much.

So next we have Gary DeShazo from the Cal-ISO.

MR. DeSHAZO: I want to just take a moment to thank you for the opportunity to come here and provide some comments, I think related to some of our perspectives about how we want to move forward in planning.

I find that every time I've been here I always walk away with a little more knowledge than what I had whenever I came in. And it appears that today I've learned that I may have a future in insurance somewhere along the way, so --

(Laughter.)

MR. DeSHAZO: -- we'll see where that goes.

In reviewing the staff report there are some comments that were attributed to our CEO, Yakout Mansour, with regard to our perspectives about the ISO's role in transmission planning. And some additional clarification that Armando Perez provided, which I think, on the surface, other than indicating that we were going to be doing something a little bit differently, that there was a little less or a little more information provided.

I was asked if I could come and maybe provide some additional comments on that. I'm not sure that -- I will shed some more light on that in terms of concepts. I'm not prepared to give you a lot of details about that. The last 60 days that we've had has been, you know, a roller coaster ride, I guess, is probably maybe a simple way to describe it. But I think what I'm learning is that the last 60 days has been about the first climb to the top. The roller coaster ride is just now going to start.

So, as I look out on the landscape I see that the sky is still blue, but the landscape, in terms of things that we're looking at and we're watching out for, are changing. And they're changing very rapidly.

With regard to the transmission planning process, maybe the best way to do this is if we think about what we're currently doing today it's done through expansion plans. This stuff is described in our tariffs and we've been doing this since the ISO essentially has been in operation.

Where the participating transmission owners go through a planning process; they develop an annual transmission expansion plan, which looks out to roughly ten years.

Typically the first five years are in a lot of detail because they need that kind of information for budgeting. But then they also look out to the tenth year to try to get a far reach out in terms of making sure that we've got our bases covered with regard to transmission.

The process is they look at the plans; they identify problems; they propose projects to resolve those. They look at the ones that are most economic. They put all that into an expansion plan and provide that to the ISO. Then we review it for those projects that are $20 million or greater in cost, it requires our board approval. Those that are less than $20 million can be approved by ISO management.

We also do what we have called our control area study or control grid study, which is we take all three expansion plans and put them into one. There's been a lot of discussion here before you about how do you do it on a statewide basis. And I think I have made some comments along the lines that what the ISO is doing is about as close as we can get in terms of coordinated planning with regard to transmission plans.

Clearly, you know, we've got transmission that covers about 75 percent of the state. So we've gotten a good portion of the way there. But, clearly, there are some missing pieces. And I think we've heard today that these are really important missing pieces.

We do that and that helps us identify if there's any seams issues. And if there are, then we turn around and pump that information back into the following year's expansion planning process.

The other thing that we do is, of course, the reliability-must run work. And that's an annual process. We only look at the next year in determining what our reliability-must run requirements are for that year. And then we've got a process that we go through to identify the generation that's needed for that. And ultimately then select for RMR agreements.

I think that from Yakout's perspective, that he sees this process as reactionary. And he's right. And with regard to what we do, we --

PRESIDING MEMBER GEESMAN: And he's probably read some of our reports over the last couple of years.

MR. DeSHAZO: Oh, I'm sure that he has. And so we look at what we do as terms of reactionary. We get the plans; we make determinations about it; and then we go do something.

Yakout has asked, and when I say asked, really it means direct, he just is nice about it when he does this, that he asks us that we need to no -- we need to be more proactive in terms of what we're doing. And so he's asked us to take a more proactive role in the transmission planning process.

We recognize that we have access to information that is not readily accessible to others. We also recognize that in terms of the work that we do with reliability-must run and congestion, that we have, I think, an opportunity to be more proactive and get in front of this, and looking at where are these issues occurring and what things can we do in order to reduce these costs.

Now, one of the comments that he made

was that we're looking at roughly $600 million in RMR costs, and I think somewhere around $300- to $400 million in congestion costs. In other words, you get up to $1 billion a year. And this is just too much. We are not necessarily seeing that this is going to be turning around very quickly.

So what he's asked is that we need to go after this stuff and we need to do it in a proactive role, a more proactive way. And what he's wanting us to do is to develop an ISO transmission plan that identifies where these areas are, and the transmission projects that could be put in place that would resolve these.

Now, I think in trying to sort of think this through our concept is that in doing this we would develop both a five-year look and a ten-year look. The five-year look, I think, is more focused on the reliability-must run and congestion types of issues. The ten-year look is looking at interconnection issues, things that we need to do in order to support our needs for importing ore power from the outside. These typically are longer term projects.

There's also the issues for the ten-year plan, because if you're thinking about ten-year types of projects, then you're talking about 500 kV, and maybe possibly even some 230 type stuff. It depends upon where it's being located.

But we believe that in doing this, given the information that we have, that we can make good judgments about what the right projects are, with the intent of selecting these in a way that will minimize the costs that are being attributed to, or paid back through the California ratepayers, at least those with the California-ISO.

The intent is Yakout has asked us that we would develop our first five- and ten-year plan prior to January of 2006. That it would be approved shortly thereafter. And then the new PTO plans, we would provide that to the PTOs. They would assess that information and if they put that into their PTO plans, we would expect to see a response back from them right around somewhere in July 1st of 2006.

Clearly, in order for us to do the process there's information that we will need to gain or collect with regard to the resource portfolios; in terms of the timeframe that we're looking at, the load data, the types of contracts, there's various things that we'll need to collect input from or on that we would have a stakeholder process. We need to define or put together some sort of a stakeholder process that we would lead to collect that information.

The projects that we propose in our plan, if PTOs include those in their plans, then the ISO Board would approve them. If they -- of course, they'll be given an opportunity to review those plans. If they come up, they have a better alternative to resolving the issues that we've identified, then they can propose those and then we would approve those.

If they chose that they don't want to build those, then we would go out for a third party and through some sort of RFP process that would need to be developed in order to accomplish that. The intent is we would intend to move forward with getting the projects constructed.

I think that with regard to the plans that are put together, one of the things that we also need to think about is the resource side and generation siting. One of the concepts that Yakout has had is that our plan should recognize that -- or should in some way send a signal to resource developers that if they were to site resources in certain locations, it would either defer or eliminate the need for transmission investment.

And then if we could look and say that that's more economical choice to make, then that's what we would do. And what he is looking for is a way to provide some sort of a transmission or base credit that would come out of the savings from not doing the transmission as opposed to the resource side.

We don't know how that would be done yet, but at least from his perspective he believes it's something that can be done, and should be offered.

We have a document that briefly is explaining this. It's still being revised. I expect that it will be posted on our website tomorrow. Sort of describing, in generalities, what we're planning to do.

We've got a lot of work in front of us clearly in order to do this. There's no doubt in my mind that we'll be able to do that But we can't do that, of course, without working with the PTOs and support from the PTOs.

But one of the things that I would like to mention is with regard to your staff report, one of the things that I was heavily involved in was the work that was occurring late last year between the three agencies, the CPUC, the CEC and the ISO in looking at ways to identify where our core strengths were, how we could apply those together and streamline the overall process in terms of identifying our transmission -- reliability needs, and then getting things done.

The ISO believes, at that time, that that was the right process. We were making incredible progress with that. And in reading the staff's report we're very much encouraged to see that that momentum has not been lost; that it's been carried through in terms of your thinking. And we believe that it's absolutely the right thing to do. That we have core strengths that we can bring to the table in terms of what our obligations are. We believe that the CEC does, as well. And that the best way to get this done is really to work out a process that really involves both of us, both of our organizations, in order to accomplish that.

PRESIDING MEMBER GEESMAN: Thanks for

your comments, Gary. Let me ask you how your department or section of the ISO has survived the budget reductions there.

MR. DeSHAZO: Well, what we have done is we had, prior to the realignment, we had an operational engineering group that reported up through Jim Detmers. Then we had the grid planning group that, prior to Terry's departure, reported directly to Terry Winter, the CEO.

And in the interim period Army was reporting to the CEO, which also happened to be Jim Detmers.

What Yakout has done, and I think he's drawing from his experience from BC Hydro or the BCTC efforts, is that he believes that you need to get the operations part and the planning part together. And they need to be working together so that the solutions that are developed aren't just about looking at long-term planning type things, but they also are trying to accommodate the operational needs, as well.

So what we have done is we have combined both the operations engineering group and the grid planning group together. It reports through two Directors; I'm one. My responsibilities are through the northern system. Richard Cashdollar is the other. His responsibilities are the southern system. Report to Army Perez, who is now a Vice President of Planning and Infrastructure Development.

We kept the number of people involved intact, although I think everybody around the company was asked to downsize. The overall organization was decreased somewhere between 20 to 25 percent in employees.

And Yakout's vision is that I guess maybe the best way -- the way I tend to look at this is that there's little left to the imagination about what he wants us to do. How we do it is left totally to the imagination.

Clearly, we have less people. We have a lot that we have been doing. We will have to find ways to either continue to do the amount of work that we've been doing with the people that we have, or simply just not do some of those things that we have.

Now, having said that, we are struggling at least within Army's group of looking at what he's asking us to do in terms of planning. Plus we've got our operational requirements now that we're dealing with. And it's not -- today, it doesn't look like it's a very simple thing to resolve. But I believe that we will resolve that.

Clearly, we have a strong vision about planning, and we want to take a role in that. Mr. Mansour wants us to do that, and he's expecting us to do that.

I think, though, that's why I believe strongly that partnering with the CEC and the other organizations and looking for a single way to do this, and focusing on our core strengths, is a way that we can make that happen.

Because I believe that there are many things that your organization can bring to this in helping us do that, that we can contribute to. And I think overall we can get the job done. But clearly, Mr. Mansour wants us to be proactive in the planning aspect, and that's exactly what we will do. And we'll be successful at doing that.

PRESIDING MEMBER GEESMAN: Well, Yakout's great benefit, in addition to his lengthy prior experience, is that he comes to the situation new and with a fresh set of eyes. Commissioner Boyd and I still regard ourselves as sufficiently new and with fresh sets of eyes, that

I'm hopeful that we don't succumb to the kind of organizational parochialism that seems to characterize state government.

But I don't think we will, I don't think we have. To give you a preview, I do believe our report this fall will carry forward many, if not all, of the same themes that our prior reports on transmission have. Probably with a fair amount of new intensity, because I think our situation has worsened since we started writing these reports.

My infrastructure soul brother, Pat Wood, in his farewell interview gave the state, and I think in all fairness gave himself and his Commission a D-plus in addressing our infrastructure needs since the crisis of 2001.

And I think that our report, to some extent, will be a letter home to one's parents as to why we got a D-plus, and how we're going to do better next semester.

I think the notion that planning needs to be more proactive than reactive is one that we will probably spend a fair amount of time on. We have been critical of the rearview mirror approach that our institutions have taken. And I think that we'll probably expand a bit on that.

I also agree that the collaborative process that was initiated late last year was an extremely good idea, and hopefully we can reinvigorate that effort. I'm disappointed that the other organization -- and I won't dwell on which one of the three of us that was -- but I know it wasn't you and I know it wasn't me --

(Laughter.)

PRESIDING MEMBER GEESMAN: -- that unilaterally suspended work on that effort. But I think it's important to start that up again. And I'm happy that our two organizations have been able to work together as closely as we have in the interim.

I would strongly recommend, and I don't know the docket number, but the Southern California Edison Company did file some comments in our docket at some point this past spring cautioning against duplication of efforts. And I think that's an important theme for each of us to follow going forward, particularly with resources for each of us being relatively constrained.

We ought to focus on these questions as best we can; make the best decisions we can. And then make them once, not revisit them again and again and again and again. We ought to come up with legally defensible results. I think that's what the people of California expect from us, and I think that's what we should be able to deliver.

But I certainly thank you for your comments and all of the help that you've provided us over the past several years.

MR. DeSHAZO: Thank you, and the same for you.

COMMISSIONER BOYD: It's hard for me to top Commissioner Geesman always in this arena, so I rarely try. But I think you should take the message back, therefore, that we both commend the ISO and yourselves for the words you brought us today and the attitude you brought us.

I'm not sure my eyes are as young as Commissioner Geesman's, and one of my terrible disappointments over the past introduction to the electricity business and the crisis and what-have-you, was the idea that in my mind it would take the combined resources of everybody in the room and probably a few others to solve California's, the nation state of California's issues. But there was always too many people inclined to say, well, that's my responsibility, I'll take it back home and take care of it. And not, therefore, enough exhibiting of teamwork.

I think the collaborative effort was good, is good and will always remain good. And it will take the combined core values, I like that term that you brought to us, of all the agencies to get us out of this dilemma. Which we're not doing a very good of getting ourselves out of yet. But I do retain hope still. So, thanks.

MR. DeSHAZO: Well, I would say that, in just some other comments, Yakout has told us his first 90 days was 70 percent inside, 30 percent outside. He has informed us that his 90 days are up. It's now your problem and you need to go. I've told you what you need to go do, now you need to go do it. And that's what we're in the process of doing.

So, now it is 30 percent of his time inside, and 70 percent of his time outside. And he clearly has a desire to work with the outside, and develop relationships. There's no doubt in my mind that that is a core in his mind, and he will do that.

Thank you.

PRESIDING MEMBER GEESMAN: Thank you,

Gary.

Okay, I'm going to go to blue cards now. Carry Downey from the Imperial Irrigation District. Is she still here? Guess we lost her.

Kevin Woodruff from TURN.

MR. WOODRUFF: Thank you, Commissioner Geesman. I'm Kevin Woodruff; I'm here representing TURN. I have two pretty quick comments.

One is a factoid we ought to keep in mind when talking about reliability criteria. There was some discussion about the City of Los Angeles' planning criteria being one-in-ten hot load plus a single largest contingency, and it produces a result, I believe that Randy Howard said, was a reserve margin of over 20 percent, or about 20 percent.

SMUD uses the same criteria and it comes up with a reserve margin of less than 15 percent, because their single largest is proportionately much smaller.

So, just because you start with a one-in-ten load forecast doesn't mean you come up with a higher criteria than 15 percent over a one-in-two load forecast.

I know the generators get excited when they hear a one-in-ten load forecast because they think their market share is going to go up. It doesn't always work that way. That's something to keep in mind.

Second item is more of a caution. There's been a lot of attention and some additional work presented today about trying to estimate, you know, the net benefits of transmission projects. I think that's -- if we've done that bad a job historically of really getting what the benefits have been, there's, you know, a lot of attention needs to be paid to that.

And I know the ISO's team process, and you know, some of the work Mr. Toolson presented today and Mr. Eto has, I think on previous occasions, there's a lot of discussion of that. I'd be very -- my caution is if you start actually being able to make reasonable estimates of what some of these extreme, you know, insurance benefits and other quantifiable benefits are, I'd be very careful about then applying a social discount rate to the stream of benefits to come up with a benefit/cost ratio.

That may be appropriate in some

instances, but that's a very heavy thumb to put on the scale of benefit/cost analysis. The danger is when you take that approach is customers may end up with a fixed cost for a project that is, over time, only going to increase their rates. That's the -- you have to be extremely careful about adopting benefit/cost criteria or benefit/cost tests that are going to disadvantage those that are going to be paying for the project. That was my -- a caution I would make on that issue.

PRESIDING MEMBER GEESMAN: And I would suggest that you should be equally cautious about burdening those who will be paying extra costs if the project does not go forward.

MR. WOODRUFF: Fair enough.

PRESIDING MEMBER GEESMAN: Such as the ratepayers in San Diego in the wake of the demise of the Valley-Rainbow project.

MR. WOODRUFF: Right, and I don't believe my client took a position on that particular, but --

PRESIDING MEMBER GEESMAN: No, but I will say during the short period of time that I was on the ISO Board in the spring of 2002, I think four or five projects came in front of the board for approval and on each of those I am proud to say that either Mike Florio or myself made the motion to approve the project. And the one of us that didn't make the motion seconded the other one's motion.

So at least the senior attorney of your organization has a distinguished record in acknowledging and recognizing and promoting the benefits of many of these projects.

MR. WOODRUFF: Yeah, Mr. Florio and I work together on a lot of resource planning issues before the PC, and take the planner's approach, and not necessarily the short-term cost minimization approach to evaluating projects, both generation and transmission. I think that's appropriate.

Again, I just -- the social discount rate is a real hammer to put on the scale, a real, you know, heavyweight to put on the scale on the side of building something. I'd be very cautious about doing that to avoid double counting, and, again, you know, potentially approving a project that will just raise rates without providing benefits that are comparable.

PRESIDING MEMBER GEESMAN: And I think

when we start seeing white elephant projects and under-utilized transmission capacity in the state, we really ought to revisit that question.

MR. WOODRUFF: That's fair, a fair comment.

PRESIDING MEMBER GEESMAN: And I hope you'll ask your grandchildren to remind my grandchildren of this point.

(Laughter.)

MR. WOODRUFF: Fair enough. Thank you.

PRESIDING MEMBER GEESMAN: Thanks, Gary.

COMMISSIONER BOYD: One of the overriding economic considerations that I love to apply to something always is pay me now or really pay me later is always a possibility. So, your caution is understood, but we have to be careful.

MR. WOODRUFF: I understand. Thank you.

PRESIDING MEMBER GEESMAN: Barry Flynn.

MR. FLYNN: Yes, thank you for giving me the opportunity to speak. When I decided to come today, I took a day off from vacation because I was in the area anyway and I wanted to essentially compliment the staff on the work that they've done and make a few comments not too much different from those that you've heard from me before.

First, I would say, I'm Barry Flynn; I'm with Flynn RCI. I'm a consultant to a number of entities, but mostly to the cities in the Bay Area, the City of Alameda, Palo Alto, Santa Clara, and the City and County of San Francisco.

And one of the themes, as Gary knows that I've been sort of pounding on over the years, is looking at total economics of transmission within load pockets.

And we've always struggled with coming up with numbers when I tried to put that out to others as to why that's important. The only thing that was publicly available was the fixed costs of RMR. And I think the last time we counted up those fixed costs, in the Bay Area were just under $200 million.

The numbers that are in your report that are quoting Yakout are greater than that. And they take into account other things. And I easily accept those.

And I wanted to try to put some of that in context, because the Commission is doing a great job, and the staff, in terms of trying to look at all the issues. But in some ways the issues are much simpler in my mind. If you really want to go after the low-hanging fruit, or go after what has an economic justification, I mean the numbers in your report are talking about $1 billion in RMR costs and local congestion costs.

If you go back and look at where economics have been done on transmission so far, fist of all let me say that, you know, in the five years I've been following the activities of PG&E and the ISO, you know, a lot of time and effort -- and a good job has been done with regard to doing studies that comply with reliability criteria.

I think people don't really understand how little has been done in the economic area. And if you look at the few cases that have been done, we're talking about first Path 15 was posed by a private developer. The ISO really did some economic studies for the first time on terms of operational economics. They developed the team methodology which took two years or more. But the example used for that was Path 26.

We have a Palo Verde-Devers study that is currently before us that's not interzonal, but it's sort of interzonal issues in terms of importing power into the state.

There's very little work that I know of

that's really gone to what does it take to reduce the local reliability costs that we're talking about that add up to this $1 billion. The smaller numbers that you see are the interzonal costs. That's where the economic studies have been done.

So my basic message was to try to encourage the Commission to align its recommendations with a lot of the early part of its report where it pointed out how big an issue this is from an economic standpoint. And I got to tell you, you know, hearing what Gary had to say, I feel like going and celebrating.

I mean I think it sounds like the ISO is really going to take a leadership role in this area. And I guess -- so my recommendation to the Commission is to, as you've talked about having a cooperative relationship, basically do everything you can to help move that process along at a rapid pace.

And I thank you for your time.

PRESIDING MEMBER GEESMAN: Thank you, Barry. As usual, those are very good points.

Others who wish to address us?

MS. GRAU: And do we have anybody on the line, on the phone, who would like to say anything?

PRESIDING MEMBER GEESMAN: Judy, I think we're done.

MS. GRAU: Okay. Thank you.

PRESIDING MEMBER GEESMAN: Thank you all very much. We'll be adjourned.

(Whereupon, at 3:39 p.m., the hearing was adjourned.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Hearing; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said hearing, nor in any way interested in outcome of said hearing.

IN WITNESS WHEREOF, I have hereunto set my hand this 2nd day of August, 2005.